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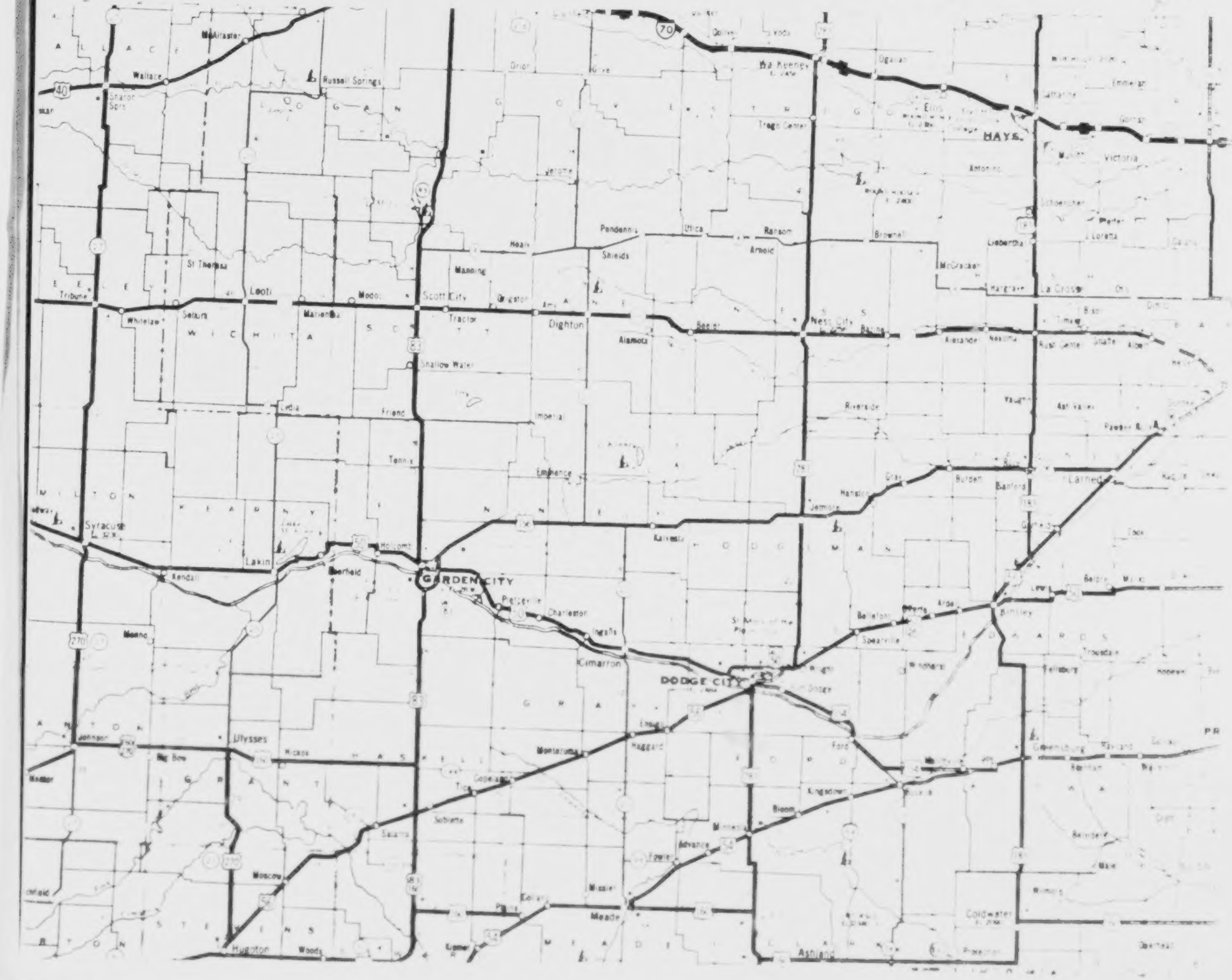
Economic Regulatory Administration
Division of Power Supply and Reliability

Compliance Problems of Small Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978: volume II - Appendices

Submitted pursuant to P.L. 95-620, Section 744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COMPLIANCE PROBLEMS OF SMALL UTILITY SYSTEMS WITH THE POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

VOLUME II

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APPENDIX A

SMALL UTILITY CASE STUDIES

CASE STUDY NO. 1
FARMINGTON, NEW MEXICO
ERA REGION 24

1.0 System Description

1.1 Service Area and Customers

Farmington's municipally-owned system services an area of about 1,600 square miles, making the city the largest municipal power producer in New Mexico. Farmington is located on the Animas River approximately 15 miles from two large coal-fired generating stations owned and operated by investor-owned utilities (IOU's): the four Corners Plant (2,234MW), owned and operated by Arizona Public Serive, and San Juan Generating Station (1,800MW), owned and operated by Public Service of New Mexico (PNM).

Farmington's only wholesale customer is Aztec, New Mexico: two to three MW are "wheeled" by Farmington from the supply generated by hydro facilities operated by Western Area Power Administration (WAPA).

Table I depicts the mix of customers and rate of power consumption in the Farmington system. The figures presented are for the month of February 1980 and are representative of that time of the year.

TABLE I. CUSTOMERS AND CONSUMPTION

	No. of Customers	Energy (kWh/yr)
Residential	17,541	117,240,000
Commercial	2,593	46,800,000
Industrial	216	160,800,000
Municipal (wholesale)	1	7,800,000
(February 1980)	20,351	332,640,000

1.2 Existing Facilities

Farmington's generating facilities consist of one small hydraulic turbine generator, one gas-engined generator, two diesel-engined generators, and four steam turbine generators at the Animas Powerplant. For practical purposes, the hydraulic and engine-driven units can be disregarded because they collectively represent less than 7.5 percent of the plant's net generating capacity, and they run less than 150 hours per year each. They are occasionally used for peaking and are available for plant start-up from a cold condition. The small (0.2MW) hydraulic unit is in intermediate service, but can supply less than 0.7 percent of the plant net generation even though the required fuel (water) is free

Presently, steam turbine units No. 1 and No. 2 are used for peaking service only, No. 3 carries an intermediate load, and No. 4 carries the base load. All four units burn natural gas with No. 2 fuel oil capability, but natural gas has been used almost entirely since the units went into service in 1957 and 1959, respectively. During 1980, these four units have generated about 45 percent of system demand, with the remainder being purchased from PJM and WAPA from coal-fueled and hydroelectric facilities, respectively. The remainder of this section

EXISTING UNITS

TABLE II

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	DUE ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
City of Farmington'		1	Steam	Peaking	NO	3.5	1957	NG	50	None	16,000	2000
		2	Steam	Peaking	NO	3.5	1957	NG	50	None	16,000	2000
		3	Steam	Inter.	NO	7.8	1959	NG	126	Oil	14,000	2005
		4	Steam	Base	NO	15.2	1959	NG	233	Oil	13,000	2010

deals only with the existing steam-powered units concerning future service because the diesels are exempt under the FUA, and because the other two units are advanced age (30 years for the gas engine and 50 years for the hydraulic turbine) and account for less than 2.5 percent of net plant generating capacity.

Table II describes the four steam units in detail.

1.3 Fuel Sources

The City has a natural gas contract with Amoco Gas Company, in effect since October 1961, which provides approximately 60 percent of the necessary fuel supply (2,000 mcf/day). Supply is from a local field five miles away, the yield of which has been declining in recent years. A second contract with the Gas Company of New Mexico, whicn was executed in late 1977 to supplement the declining Amoco supply, supplies 40 percent of the system's fuel supply (1,000 mcf/day). The City expects to extend both contracts when they expire in October 1981. No gas supply problems have been experienced in the past nor are they anticipated in the next 15 to 20 years. The City, in fact, expects there to be a local surplus of natural gas.

1.4 Demand Projections

Farmington's system load is expected to grow at a rate of about five percent annum through the year 2000. Table III outlines the supply and demand picture for 1980. System "capability" includes reserve capacity while "annual energy" is a total of variable loads handled by the ssytem. The "reserve requirement" is necessary to maintain supply in the event of an equipment failure at any of the supplying plants, at any time of year.

TABLE III. 1980 EXISTING RESOURCES AND DEMAND PROJECTIONS

	Capability (Net MW)	Annual Energy (Net kWh)
City-Owned Generation		
Hydro - Conventional	0.2	1,400,000
Internal Combustion	2.2	400,000
Steam - Gas/Oil	30.0	103,000,000
	32.4	104,800,000
Federal Hydro Purchases (WAPA)		
Colorado River Storage Project	16.0	76,500,000
Other Suppliers		
PNM	21.0	175,500,000
Total	69.4*	357,000,000**

---

* Total Resources for 1980 (includes 3 MW reserve requirement, and hydraulic and engine units).

** Total Anticipated System Demand, Base on Normal Annual System Factor.

As stated above, the system load is expected to grow at a rate of five percent per annum with the following results:

TABLE IV. PROJECTED DEMAND

Year	Average Base Load	Peak Load (Summer)
1979	33.6 MW	58 MW
1980	37.0	64
1985	49.9	86
1990	61.5	106
1995	77.7	134
2000	98.6	170

2.0 Fuel Use Act Implications

2.1 Applicability

The four steam-powered units are classified as an "existing electric powerplant" under the FUA definition: the diesel and hydroelectric facilities are not included under the FUA definition and are, therefore, exempt from the Act's prohibitions.

Because the four steam-powered units are in combination at the same site and each has a heat input rate equal to or greater than 50 million Btu per hour, the heat input rates are aggregated toward the 250 million Btu per hour FUA threshold for a combined heat input rate of 459 million Btu per hour at the Animas Powerplant. None of the four steam-powered units, therefore, is exempt from the prohibitions of the FUA.

Had the FUA not been passed by Congress, the Superintendent, Mr. Dale Carlsen, indicated that the City probably would have invested in combined cycle units for some capacity expansion, and would not have emphasized in its feasibility studies technologies based on alternate fuels or joint ownership opportunities. Mr. Carlsen did state that natural economies of scale and proximity of large coal-fired plants, existing and planned, had compelled the City to investigate joint ownership possibilities before passage of the FUA. The City is reticent about becoming too dependent upon or entangled with the neighboring investor-owned utilities for fear of being absorbed.

2.2 Compliance Strategies

2.2.1 Existing Units

With respect to the four steam-powered units, Farmington has basically four options in complying with the FUA's prohibitions:

- o Fuel conversion (oil or alternate fuels);
- o System compliance option;

- Permanent and/or temporary exemptions; and
- Sale of system.

Fuel Conversion: Although the four steam-powered units have the capability of using No. 2 fuel oil without requiring modifications the City has at least temporarily rejected that option because of the local availability of natural gas and the diseconomies of using oil. The use of oil in existing units is also subject to prohibition orders issued by the Secretary of DOE, even though the statutory burden is on DOE to prove that it is financially feasible to burn alternate fuels in the powerplant, and that the powerplant had the technical capability to use alternate fuels or has such technical capability without substantial physical modification or reduction in the powerplant's rated capacity. The City was also aware of the oil "back-out" legislation pending in Congress and did not think that converting to oil would be a long-term solution to the FUA prohibitions.

The City had also ruled out conversion to alternate fuels which would require substantial modifications to the units because of their advanced ages. Local coal fields are located within 15 miles of the City, and strip mining has been proceeding for many years: the Four Corners Plant and the San Juan Generating Station are both mine-mouth powerplants. Although the City has not hired a consultant to study the feasibility of conversion, Mr. Carlsen noted that converting the gas-fired units to coal would require new boilers and advanced pollution control technology to meet New Mexico's stringent environmental regulations.

Mr. Carlsen reported that a synfuels plant was being planned for the area by Texas Eastern Synfuels Corporation, a subsidiary of Texas Eastern Transmission, and by Utah International. The medium-Btu Coal gasifier, which has been in planning for ten years, would be built within 35 miles of the City at an estimated cost of $3 billion. Although the plant presently has a 1983-84 start-up date, Mr. Carlsen indicated that Texas Eastern was having problems negotiating with the Navajo Indians and the Bureau of Land Management (BLM) for the strip mining of coal on the reservation and on government lands. If the plant is constructed as planned and the cost of the synthetic gas is reasonable, the City will negotiate for a supply of alternate fuel to extend the lives of its existing units past 1990.

Obtaining a supply of syngas might also provide a basis for seeking a permanent exemption for plants using fuel mixtures containing natural gas or petroleum.

System Compliance Option: Another compliance strategy being pursued by the City for its existing gas-fired units is the system compliance option authorized under Title V of the FUA. In August 1980, the City filed a proposed system compliance plan with DOE/ERA. The important elements of the plan are as follows:

- Between 1980 and 1990, Farmington will not use natural gas in its system in greater proportion than it was used in the 1974-1977 base period, which proportion was essentially 100 percent;
- On or after January 1, 1980, Farmington will not use natural gas in its system in excess of 20 percent of the base period usage or, if lower, the minimum peak load requirment for the calendar year;
- From 1995 to 2000, Farmington will not use natural gas as a

primary energy source, except for intermediate load and peak load; and

- On or after January 1, 2000, Farmington will not use natural gas in its system at all, except in case a temporary extension is obtained.

Permanent and/or Temporary Exemptions: Farmington's proposed system compliance plan presupposes that the City's existing units will be used only for peak load and reserve purposes on or after January 1, 1990, even though the units are not scheduled to be retired until the 2000-10 period. That being the case, the City is also considering filing for its two larger units a petition for a permanent exemption for peak load powerplants under Title III of the Act. In its petition and Fuels Decision Report, the City will be required to demonstrate the following:

- The units will be used solely for peaking;
- A denial of the exemption will result in an impairment of reliability of service; and
- Modifications of the units to comply with FUA's prohibitions is technically infeasible or will result in an unreasonable expense.

The advantages of permanent peak load exemption over the system compliance option are that natural gas usage in the two exempt units will not be tied to 20 percent of the base period and that usage can extend beyond the year 2000.

The City is also reviewing the feasibility of cogeneration. There are two schools within a mile of the Animas Powerplant which are presently heated by natural gas. It would be possible to supply one or both schools with heat from the plant, depending on the economic benefits, but the amount of fuel saved would be minor. The City might also consider pursuing a permanent exemption for cogeneration for its existing units, the grant of which is within the Secretary's discretion.

A representative from DOE indicated at the City's compliance option meeting in Denver on April 2, 1980 that the City could pursue both a permanent exemption and a system compliance plan, but the exemption petition must be granted before the system compliance plan is approved by DOE. If the exemption peition is granted before the compliance plan is approved, the exempt units are removed, in effect, from the "system" covered by the plan. If the Title V compliance plan is approved before the exemption petition is granted, however, the system owner is forever barred from seeking or obtaining any exemption under Title III. The decision concerning whether to go forward with a compliance plan does not have to be made until the plan has been negotiated with DOE, and DOE has given the system owner notice of its intent to approve the plan. The City can proceed with the exemption petition up to that point before making any ultimate decision.

Sale of System: Selling its system is also an alternative to undertaking the costs of compliance with the FUA. Indeed, Mr. Carlsen stated that PNM propositions every new City council to sell the Farmington system but the City is strongly committed to public power.

2.2.2 New Capacity

Because the City's FUA compliance strategy contemplates using its existing units after 1990 only for peak load and reserve, the City is reviewing all of the following options for obtaining base load:

- Construction of a plant using alternate fuels;
- Construction of a jointly-owned plant using alternate fuels or purchase of a share of such a plant under construction or being planned; and
- Purchased power.

Construction of a New Plant: Although the City thinks that its options with respect to alternative technologies are limited by the diseconomies of scale associated with units smaller than 100MW, the City is studying a number of alternative technologies with the idea of perhaps constructing a new plant on its own. The City has considered constructing its own coal-fired unit, but does not expect to do so in the next ten years. The City is also trying to purchase a local coal lease in order to obtain a source for its own future plant or to use as a "bargaining chip" in a joint action project.

The City is also considering installation of several large diesel generators totalling 22MW of peaking capacity to accommodate projected growth between 1980 and 1995. The diesel capacity, which can be installed in a relatively short period of time--less than three years from order--is presently exempt from the prohibitions of FUA. Supplies of No. 2 diesel fuel could become a problem, and a heavy fuel oil operation might be more dependable in the long run.

Another alternative technology being studied by the City is construction of a number of hydroelectric facilities on the Animas River below the proposed Animas-La Platta Project, being considered by the Bureau of Reclamation (BuRec). Although the primary purposes of the project are to supply municipal water to Durango, Colorado, and irrigation water to the adjacent properties. BuRec also contemplates releasing water from the reservoir into the Animas River at a rate of 2,300 cfs. Because there is a 1,000-foot drop in elevation between the proposed dam site and the City of Farmington, the project could generate up to 3,000MW of power if appropriate hydroelectric facilities were constructed on the Animas. No final decision to proceed with the project has been made by BuRec. A Federal loan for hydroelectric facilities could make this alternative realistic.

Finally, the City has submitted proposals to DOE under the Appropriate Small Community Experiment Program for funding for a 50-100 KW hydroelectric project on the Animas River and for a 1MW solar project.

3.0 Joint Ownership

Even though none of the City's plans for its own unit has gone beyond the study stage, the City has been actively negotiating the purchase of shares of large coal-fired units under construction or being planned by other utilities. Prior to recent passage of enabling legislation by the New Mexico Legislature, political subdivision could not build or own generating facilities outside of their political boundaries: they could buy power from but not capacity in, such plants. The passed enabling statute authorizes political subdivisions, including municipalities, to issue bonds for joint construction and/or ownership of generating facilities, but does not allow the creation of a joint agency of two or more political subdivisions with independent bonding authority. Mr. Carlsen indicated that the legislation was lobbied strongly by the investor-owned utilities to exclude such joint agency powers.

PROPOSED UNITS

TABLE V

STATION NAME	UNIT	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	RATED CAPACITY	DUE ON-LINE COMMERCIALLY	PREFERRED FUEL	ALTERNATE FUEL	HEAT INPUT RATE	MAXIMUM HEAT RATE**	RETIRE-MENT DATE
San Juan	4	Steam	Base	NO	450*	1982	Coal	Oil	NA	10,000	NA
Undesignated	NA	Steam	Base	NO	100***	1985	Coal	Oil	NA	10,000	NA

* Farmington to own 50 MW. - Plant being constructed by Public Service Company of New Mexico.

** Estimated

*** Commencement of construction in 1982 for 100 MW, if approved and funded.

The City is also considering joint ownership options with nearby municipalities: Truth or Consequences, N.M., Gallup, N.M., and Durango, Colorado.

4.0 Purchased Power

The purchase of power from, as opposed to owning capacity in, nearby plants is perceived by the City as a less desirable alternative than either construction of its own unit or joint construction and/or joint ownership of a unit. Purchased power is perceived primarily as an interim solution to anticipated growth and compliance with the FUA. The City's proposed system compliance plan contemplates displacement of the City's existing contract with PNM for 19MW of power from San Juan Generating Station by the purchase of 50MW of capacity in that the purchase of 16MW of power from WAPA will also remain constant during the 1980-1990 period.

5.0 Conclusions

The City of Farmington has reacted to the FUA without panic and with a high degree of resourcefulness. The City has evaluated its position accurately and is diligently pursuing its most appropriate short-term options without foreclosing other alternatives which may become more attractive in the long-term. The best short-term options (1980-2000) are the following:

- Pursue a permanent exemption for the larger existing gas-fired units based on peak load powerplants or fuel mixtures containing natural gas to extend their lives beyond the year 2000;
- Pursue (at the same time) a system compliance plan to extend the lives of the existing units beyond the year 1990, if the permanent exemption is not granted; and
- Pursue joint ownership options with nearby IOU's, municipalities and/or coops to obtain base load power produced by facilities which will use alternate fuels other than oil.

CASE STUDY NO. 2
LAMAR, COLORADO
(LAMAR UTILITIES)
ERA REGION 24

1.0 SYSTEM DESCRIPTION

1.1 Service Area and Customers

Lamar, located in southeastern Colorado, is a predominantly agricultural and ranching community. Lamar's municipally owned electric utility, which is managed by an autonomous utilities board, services a retail area of 167 square miles, including the towns of Wiley and McClave, Colorado. Lamar also supplies wholesale power in a total amount of about 2MW to the nearby towns of Holly and Granada, Colorado.

Table I presents the system composition of retail customers and their consumption rates, which include the 1.2MW supplied to Wiley and McClave.

TABLE I. CUSTOMERS AND CONSUMPTION

	No. of Customers	Energy (KWH/yr.)
Residential	3,651	21,676,000
Commercial	801	27,834,000
Industrial	13	13,051,000
Municipal (wholesale)	2	17,521,000*
TOTAL	4,567	80,822,000

*The towns of Holly and Granada receive about a 2MW supply with a summer peak of 2.55MW on a wholesale contract. Total is Radian estimate.

1.2 Existing Facilities

Generating equipment at the Lamar Powerplant consists of two 1000KW dual-fuel powered generators and four steam turbines which have a total rated capacity of 38 megawatts (MW). The net capability of the plant is 35.8MW, although steam Units No. 1 and No. 2 are regarded as "retired," thereby reducing the net by some 4MW. (Net capability is that amount of power that can be delivered to the distribution system, the remainder being used internally.) Units No. 1 and 2 could be returned to service, but the need to do so is not anticipated because an abundance of more efficient generating capability exists in-house. Units No. 1 and 2 are laid up in a "dry" condition.

The four service units (Units No. 3-6) are natural gas-fired with No. 2 fuel oil backup capability. Unit No. 6 (24.8MW net) is the "base load" unit which can meet the present maximum peak demand (summer) of 18.9MW, and which generates about 90 percent of system requirements. Unit No. 5 (5MW net), which is maintained on "warm" standby, is regarded as reserve capacity.

Units No. 3 and 4 are piston engine-driven units with 1MW capability each and with dual-fuel capability: they are normally run on 95 percent natural gas with 5 percent No. 2 fuel oil for ignition, but can run as diesel engines on 100 percent No. 2 fuel oil. These machines only run a few hours a month and are regarded as "standby" capacity to be brought on-line with the No. 5 steam unit in the event of an outage of No. 6. They lend quick response capability to avoid purchase of outside power that could result from an outage of No. 6.

The City's facilities generate about 90 percent of system requirements with the remaining 10 percent, or about 2MW, supplied by the hydroelectric facilities of the Western Area Power Administration (WAPA). The power supplied by WAPA is regarded as "intermediate load" power.

Table II describes the existing plant equipment in detail.

1.3 Fuel Sources

The City has four natural gas contracts to supply its demand. The City's primary source is the local Barrell Springs Field, which is owned by Tom Brown, Inc., of Midland, Texas, Michigan-Wisconsin Pipeline, and Texas Oil and Gas with whom the City has contracts for the life of the field. Lamar owns the gathering system and pipeline to the field which consists of 11 existing wells with an estimated remaining life of 12 to 15 years. Most of the wells have a maximum efficient rate of production of less than 250 million Btu's per day, and together produce about 2.5 million cubic feet per day (cfd), varying from 1.5 to 5 million cfd during the year.

The City also has a contract for interruptible supply with People's Division of Northern Natural Gas for a maximum 1 million cfd.

The City has had no problems obtaining natural gas in the past and anticipates none in the foreseeable future.

1.4 Demand Projections

Load projections based on a growth rate of 5.1 percent have been tabulated by R. W. Beck and Associates (10/04/79) through the year 2020. The figures are presented below as Table III. The table indicates that the base load unit's capacity will be almost fully utilized by the end of 1981, and additional supplies will be required thereafter.

2.0 FUEL USE ACT IMPLICATIONS

Units No. 5 and 6 are classified as an "existing electric power plant" under the FUA definition because their heat input rates (No. 5--96.8, No. 6--325) each exceed 50 million Btu's per hour for a combined total of about 422 million Btu's per hour.

Retired Units No. 1 and 2, though located at the same site, would not be subject to the prohibitions of the FUA because their fuel heat input rates would be less than 50 million Btu's per hour, even if they were reactivated.

Even though gas-fired, Units No. 3 and 4 are piston engine-driven and are, therefore, exempt from the prohibitions of the FUA.

Had the FUA not been passed by Congress, the City of Lamar probably would have pursued essentially the same options, principally joint ownership, syngas, and cogeneration, which it has pursued. After the gas and oil "crunch" of the early 1970's, Mr. Carnahan indicated that all of the City's planning has been directed toward technologies based on alternate fuels.

2.1 Compliance Strategies

2.1.1 Existing Units

With respect to Units No. 5 and 6, Lamar has basically three options in complying with the FUA's prohibitions:

- o Fuel conversion (oil or alternate fuels);

EXISTING UNITS

TABLE II

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	DUE ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
Lamar Light & Power Plant		3	Piston Engine	Stand-By	--	1.0	1946	NG	8.38	Oil	8,387	2000
Lamar Light & Power Plant		4	Piston Engine	Stand-By	--	1.0	1949	NG	9.17	Oil	9,170	2000
Lamar Light & Power Plant		5	Steam	Warm Stand-By	NO	5.0	1952	NG	96.8	Oil	16,134	1992
Lamar Light & Power Plant		6	Steam	Base	YES*	24.8	1972	NG	325.0	Oil	13,000	2005

* This is proposed upon start-up of the biogas plant.

TABLE III. LAMAR ELECTRICAL CAPACITY AND ENERGY PROJECTIONS (10/04/79)*

YEAR	CAPACITY REQUIREMENT (KW)	ENERGY REQUIREMENT (MWH)	ANNUAL LOAD FACTOR (PCT)	GROWTH RATES - PERCENT			
				CAPACITY		ENERGY	
				(1)	(2)	(1)	(2)
1979	22071	90097	46.6	5.1	5.1	5.1	5.1
1980	23197	94692	46.6	5.1	5.1	5.1	5.1
1981	24388	99522	46.6	5.1	5.1	5.1	5.1
1982	25623	104597	46.6	5.1	5.1	5.1	5.1
1983	26930	109932	46.6	5.1	5.1	5.1	5.1
1984	28303	115538	46.6	5.1	5.1	5.1	5.1
1985	29747	121431	46.6	5.1	5.1	5.1	5.1
1986	31264	127624	46.6	5.1	5.1	5.1	5.1
1987	32858	134132	46.6	5.1	5.1	5.1	5.1
1988	34534	140973	46.6	5.1	5.1	5.1	5.1
1989	36295	146163	46.6	5.1	5.1	5.1	5.1
1990	38146	155719	46.6	5.1	5.1	5.1	5.1
1991	40092	163681	46.6	5.1	5.1	5.1	5.1
1992	42136	172007	46.6	5.1	5.1	5.1	5.1
1993	44285	180750	46.6	5.1	5.1	5.1	5.1
1994	46544	190000	46.6	5.1	5.1	5.1	5.1
1995	48918	199690	46.6	5.1	5.1	5.1	5.1
1996	51412	209874	46.6	5.1	5.1	5.1	5.1
1997	54034	220577	46.6	5.1	5.1	5.1	5.1
1998	56790	231827	46.6	5.1	5.1	5.1	5.1
1999	59887	243650	46.6	5.1	5.1	5.1	5.1
2000	62731	256078	46.6	5.1	5.1	5.1	5.1
2001	65930	269136	46.6	5.1	5.1	5.1	5.1
2002	69292	282862	46.6	5.1	5.1	5.1	5.1
2003	72826	297288	46.6	5.1	5.1	5.1	5.1
2004	76540	312450	46.6	5.1	5.1	5.1	5.1
2005	80444	328385	46.6	5.1	5.1	5.1	5.1
2006	84546	345132	46.6	5.1	5.1	5.1	5.1
2007	88858	362734	46.6	5.1	5.1	5.1	5.1
2008	93390	381233	46.6	5.1	5.1	5.1	5.1
2009	98153	400676	46.6	5.1	5.1	5.1	5.1
2010	103159	421111	46.6	5.1	5.1	5.1	5.1
2011	108420	442587	46.6	5.1	5.1	5.1	5.1
2012	113949	465159	46.6	5.1	5.1	5.1	5.1
2013	119761	498882	46.6	5.1	5.1	5.1	5.1
2014	126869	513515	46.6	5.1	5.1	5.1	5.1
2015	132288	540020	46.6	5.1	5.1	5.1	5.1
2016	139084	567501	46.6	5.1	5.1	5.1	5.1
2017	146125	596507	46.6	5.1	5.1	5.1	5.1
2018	153578	626928	46.6	5.1	5.1	5.1	5.1
2019	161410	658902	46.6	5.1	5.1	5.1	5.1
2020	169642	692508	46.6	5.1	5.1	5.1	5.1

(1) Growth rate since the previous year.

(2) Average compound growth rate since the last year of the historic data.

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* R.W. Beck and Associates for the Arkansas River Power Authority.

o Permanent and/or temporary exemptions; and

o Sale of system.

The City did not file a declaration of intent to prepare a system compliance plan with the Department of Energy by December 31, 1979, so the system compliance option under Title V of the Act is not available to the City.

Fuel Conversion: Although Units No. 5 and 6 have the capability of using No. 2 fuel oil, the City has rejected that option because of the local availability of natural gas, the diseconomics of using oil, and the long-term instability of oil supply.

An October 1977 report prepared for the City by Stearns-Roger, Consulting Engineers, assessed the feasibility of converting Unit No. 6 to coal. Adding to the existing No. 6 unit, a coal-fired boiler of 20MW capacity which was estimated to cost $19.3 million (1981 dollars), without sulfur dioxide pollution control. An additional $1.5 million (1981 dollars) would be added to that cost if such a control were required to meet air quality parameters.

With an increase in the cost of generation of $0.01328 per KWH and with a reduction in capacity, the City rejected the coal conversion option as being too costly.

The Stearns-Roger study also considered cogeneration of steam from the No. 6 unit to outside users or of using the steam at the power plant, for other than electricity generation. The cogeneration feature could be added to No. 6 for possibly as little as $20,000 (1980 dollars), and the City will implement it in connection with its proposed syngas plant.

The Stearns-Roger study provided impetus for the City's investigation of the feasibility of converting biomass to syngas (methane) using cow manure from nearby feedlots as the raw material. In 1977, the City hired the consulting firm of CH2M-Hill to do a feasibility study for a biogas conversion facility adjacent to the existing power plant. The syngas plant, designed to supply one million cubic feet per day at 1000 Btu's per cubic foot of gas, was determined to be a highly feasible option. At a cost of $14 million, the plant is anticipated to supply one-third of the system's total demand for gas and to replace the City's contract with People's Division of Northern Natural Gas. The No. 6 unit will supply the syngas plant with 26,000 pounds per hour of 50-pound steam. The City anticipates letting the contract for the syngas plant in October 1980, and expects the plant to be on-line within 18 months with an additional six-month start-up period.

The City is also investigating cogeneration in connection with the syngas plant. The syngas plant is expected to provide two usable waste heat sources: stack gases and warm water from the plant's once-through cooling system. The possible uses for the waste heat sources include irrigation and space heating. A college and a commercial producer have also expressed interest in using the sources in the distillation of fuel alcohol.

The City is also monitoring the progress of the 5MW solar unit being constructed by Public Service of New Mexico, but has not engaged a consultant to study the solar option. The City applied to DOE, but was not selected, to participate in the project involving a 25MW solar retrofit of an existing unit.

Permanent and/or Temporary Exemptions: Because the City would like to fire the No. 6 unit on some natural gas past 1990, the City has hired a consultant to study which permanent and/or temporary exemptions might be obtained to extend its life to at least 2005, the proposed retirement date. Among the exemptions being studied are the following:

- Temporary exemption for future use of synfuels;
- Permanent exemption for fuel mixtures containing natural gas or petroleum;
- Permanent exemption for cogeneration; and
- Permanent exemption for peak load power plants.

If the City's plans to obtain base load capabity in coal-fired units under construction are realized, it is likely that the City will pursue a permanent exemption for peak load power plants for at least the No. 6 unit.

Sale of System: Although the Superintendent, Mr. Bill Carnahan, indicated that a number small utilities nationally were considering selling their generation and transmission facilities to larger utilities as an alternative to compliance with the FUA, he indicated that the sale of the Lamar system has not been considered a local political issue. He attributed this to two situations unrelated to the FUA. First, the Colorado investor-owned utilities have not attempted takeover efforts. He pointed to the 30+ municipally owned systems in Colorado versus the six such systems in New Mexico. Second, Lamar Utilities Board is an autonomous board, less subject to external political influences.

Mr. Carnahan indicated that the City's commitment to public power was less philosophical than economic: in other words, so long as public power is competitive, the City will probably retain municipal ownership of the system.

2.2.2 New Capacity

The City's efforts to obtain base load from plants using alternative technologies preceded passage of the FUA. The City has reviewed and is still studying all of the following options, any one of which, in combination with some type of permanent exemption for Unit No. 6, would relieve the City's FUA compliance problems:

- Construction of a plant based on an alternative technology;
- Purchased power; and
- Construction of a jointly owned plant based on an alternative technology or purchase of a share in such a plant under construction or being planned.

Construction of a New Plant: The 1977 Stearns-Roger study also analyzed the feasibility of the City's constructing a new coal unit. The study analyzed three alternatives:

- Addition of a new 20MW coal-fired unit (new boiler and turbine) without scrubbers at a cost of $25.9 million (1981 dollars) or $0.06417 per KWH:
- Addition of a new 20MW coal-fired unit (new boiler and turbine) with scrubbers at a cost of $27.3 million (1981 dollars) or $0.70121 per KWH; and
- Addition of a new 45MW coal-fired unit (new boiler and turbine) with scrubbers at a cost of $39.1 million (1981 dollars) or $0.05609 per KWH.

A new 20MW coal-fired unit, used in conjunction with the existing No. 6 gas-fired unit, could only handle the system's projected capacity requirement through 1992; that assumes some type of permanent or temporary exemption can be obtained from Unit No. 6 which allows Lamar to burn gas past 1990.

The cost estimate for the 45MW coal-fired unit assumed that the No. 6 turbine would be used in conjunction with a new turbine: the proposed 45MW coal-fired unit, therefore, could only handle the system's projected capacity requirement through 1993. In any case, Lamar Utilities Board rejected all three alternatives as being too expensive, particularly compared with the cost of the syngas plant which was studied by CH2M-Hill concurrently with the Stearns-Roger study. The City also emphasized the site problems with adding a coal unit because the existing acreage is insufficient and because there are coal transportation problems. The nearest developed coal source is in Wyoming, 400 miles away: the small mines in Canyon City and Florence, Colorado, 200 miles away, are already committed, according to Mr. Carnahan.

3.0 Joint Ownership

The City's most vigorous planning efforts have concerned joint ownership options which the City has pursued since 1976. In that year, the Cities of Lamar, La Junta, Las Animas, Trinidad, and Walsenberg, Colorado, and Raton, New Mexico, formed a nonprofit corporation to study collective action. The corporation hired Lutz, Daily and Brain to study basically three alternatives: adding generating capacity to individual member systems, purchasing all power from another utility, and joint action. The consultant recommended a 40MW coal-fired plant, jointly owned by the cities, which the cities rejected because of the diseconomies of the project's scale.

Arkansas River Power Authority (ARPA) was officially created by contract in March 1979, pursuant to enabling legislation passed by the Colorado legislature, which authorized two or more Colorado municipalities or out-of-state municipalities within 15 miles of the Colorado border to contract to form a joint power agency. Consisting of the aforementioned cities, ARPA has the following general power and duties:

- Power to plan, construct, and own generation and transmission facilities in its name; and
- Power to independently issue bonds and notes to finance facilities.

Individual member utilities retain the following rights:

- Right to secede from ARPA at any time, but presumably subject to contractual obligations to take certain amounts of power for ARPA projects in which the seceding city has agreed to participate;
- Right to vacate from any individual ARPA project although all members must pay planning costs; and
- Right to reconsider participation in any individual project if any one member opts out of the project.

ARPA engaged R.W. Beck and Associates to do seven new feasibility studies of ARPA's options and of each member city's options. The final draft report of Lamar's options determined that all three of the City's best alternatives were with ARPA. Those alternatives, in descending order of preference, are as follows:

- ARPA purchases 50MW of capacity out of each of Public Service of Colorado's (PSC) coal-fired Southeastern Plant Unit No. 1 (470MW) and Unit No. 2 (470MW), due on-line commercially in 1985 and 1986, respectively, and purchases of 50MW of capacity out of the City of Colorado Springs' coal-fired Nixon Unit No. 2 (208MW), due on-line commercially in 1988;
- ARPA purchases 75MW of capacity out of each of PSC's Southeastern Plant Unit No. 1 and No. 2; and
- If PSC's Southeastern Plant is not constructed, ARPA purchases 150MW of

capacity out of the City of Colorado Springs' Nixon Unit No. 2.

Mr. Carnahan indicated that the Southeastern Plant units are still on-schedule for 1985 and 1986, respectively. At present, ARPA members have negotiated a letter of intent to buy into the Southeastern Plant, but an ARPA proposal has not been formally acted upon by the members. ARPA is negotiating a participation agreement with PSC, and Mr. Carnahan estimated that the agreement would probably be finalized within six to eight months. Mr. Carnahan expected ARPA to sell bonds within a year to construct some needed transmission facilities.

As suggested earlier, if the City's ARPA alternatives are realized, the City should have no problems in complying with the FUA by 1990.

4.0 Purchased Power

At present, the City purchases ten percent of its power from WAPA. The City has no plans to increase to expand its purchases in the future, unless the City's joint action alternatives do not work out as expected. The purchase of power has a higher priority than construction of the City's own new plant, however.

5.5 Conclusion

Lamar Utilities have invested an extraordinary amount of time and effort in planning its future base load capacity around alternate fuels, principally coal. These plans were conceived not as a response to the prohibition of the FUA, but because management read the "handwriting on the wall" with respect to oil and gas supplies and prices in the middle 1970's. As a consequence, the City's plans, which incidentally should bring them into compliance with the FUA by 1990, are fairly advanced. These plans are as follows:

- o Proceed with joint ownership options through joint agency (ARPA) or independently with nearby IOU's municipalities, and coops to obtain base load power produced by facilities which will use alternate fuels other than oil; and

- o Pursue permanent exemptions for peak load power plants, cogeneration, or fuel mixtures for Units 5 and 6 to extend their lives beyond 1990.

CASE STUDY NO. 3
DOVER, DELAWARE
EPA Region 5

1.0 System Description

1.1 Service Area and Customers

Dover's municipally-owned system services an 88 square mile area inclusive of the city corporate limits and surrounding rural areas. Dover, located in Northcentral Delaware, is the largest municipal utility in the state and is a member of the PJM powerpool. The utility services 12,000 residential customers and 1,540 commercial/industrial customers. Its largest users are General Foods (12-15MW), Dover Air Force Base (12-15MW), and Scott Paper Company (2-3MW). There are no wholesale customers. Dover Municipal sells and purchases power with the PJM pool through Delmarva Power and Light Company.

1.2 Existing Facilities

Dover's generating facilities consist of two small gas/oil burning units (15MW net each) which are coal capable, and a 104MW unit which operates on natural gas and oil. The total net generating capacity for the system is 134MW. Table I provides additional information on these units.

The system has a summer peak of 93MW (1978) and has seasonal variation of purchased power demands, based on economy load and economy savings. The units are up and down based on the price of purchased power. No power is exported except for obligations to the PJM pool which increases as load increases.

1.3 Fuel Sources

Dover receives its natural gas from Eastern Shore Gas Company on a year-to-year interruptible contract which can be extended at any time, and can be amended monthly based on the availability of excess gas. Long-term contracts are held with Petroni Oil for 36-40 million gallons per year. These are the only fuel suppliers for the municipal system.

Presently, there are no supply problems with either natural gas or oil. During occasional supply crunches, the price of oil increases primarily due to having to pay for outside supply. There are no natural gas supply problems, and Robert Schucker, Utility Manager, expects natural gas to be in plentiful supply in the years ahead.

1.4 Demand Projections

Demand forecasts are designed on summer peak loads. Dover expects continued growth through 1988-89 years. The 1978 peak was 93MW and projections range from 105MW for 1980-81, 116MW for 1984-85 to 141MW for 1988-89. The system is expected to meet the projected demand and maintain required generation with capacity expansion (see Section 2.2.2) on schedule.

2.0 Fuel Use Act Implications

2.1 Compliance Strategies

The Fuel Use Act (FUA) has had minimal impact on the Dover operations. Presently, the utility has a temporary public interest exemption for five years which will enable it to continue using natural gas. Providing natural gas is available, the utility plans to refile for another exemption as the first one expires. This plan will enable Dover to utilize their existing generating capacity to maximum extent until new generation is established (see Section 2.2.2).

EXISTING UNITS

TABLE I

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	DUE ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
McKee Runn	Dover	1	Steam	Base	NO	15	1961	NG	-	Oil	10,800	U
McKee Run	Dover	2	Steam	Base	NO	15	1962	NG	-	Oil	10,800	U
McKee Run	Dover	3	Steam	Base	NO	104	1975	NG	-	Oil	11,000	U

2.2.1 Existing Units

The design of the Dover units enables the utility to burn gas, oil or coal in the two smaller generators. Unit 3 can burn either gas or oil.

Natural gas is the preferred boiler fuel when it is available. the use of gas reduces maintenance and machinery wear more than if the units were on oil. The cost for natural gas is easily competitive with the price for oil. In addition, by using natural gas as the boiler fuel, the system saves approximately 12 million gallons of oil per year.

While the two small units are coal capable, the utility would have to install particulate controls before switching to coal. Dover converted to oil in the early 1970's and has since decreased its area capacity for handling coal storage; the former area now occupied by oil tanks. In addition, there would be a high expense for the pollution control equipment for those size units ($2 million).

2.2.2 New Capacity

The City of Dover is examining the feasibility of constructing and operating a new coal-fired unit in the 200-250MW range. Based on the utility's demand projections, the new unit will be needed for the 1987-88 years. A consulting firm is presently preparing a report, due in January 1981 on the siting, design engineering and operating parameters to be considered. Some thought may be given to a refuse-derived fuel option for this facility also.

3.0 Joint Ownership

The State of Delaware enacted joint action legislation in 1978. In 1979, the Delaware Municipal Electric Corporation was established; made up of the municipal utilities in the state including Dover. Presently, the principal concern for the municipals is obtaining access to interconnections with the transmission system which is owned and operated by Delmarva.

The Municipal Corporation has no immediate plans for building their own generating station, though purchasing portions of plants is being considered. With the possibility for building and operating their own unit, the City of Dover chose not to participate in the joint ownership organization. Dover, the largest municipal utility in the state, had been a leader in supporting joint action legislation.

4.0 Purchase Power

It is uneconomical for Dover to purchase bulk power at the expense of reducing generation. Power purchased off the PJM pool is offset by the power sold to same.

Dover is not considering the sale of its system to a larger utility as a compliance strategy.

Dover is investigating the possibility of purchasing a share (50MW) of Delmarva's proposed Vienna plant (466MW) which is scheduled for 1987. The utility has also been approached by Philadelphia Electric regarding power purchase.

5.0 Conclusions

Dover municipal has no serious compliance problems with the FUA. They have exercised options for public interest exemptions to allow for continued use of natural gas.

Delay or cancellation of the proposed coal-fired unit, scheduled for 1987-88, would have very serious implications for the utility. The plant is expected to relieve the natural gas use into the 1990's. Without the coal-fired capacity, there will be some rigid compliance schedules to meet, based on projected demand. The purchase of additional power is the least favored option without the coal plant.

The coal-fired plant will not be without its own problems, however, Dover is concerned about site selection, availability of low sulfur coal and railway access. The State of Delaware regulates coal sulfur content before combustion rather than with emissions.

Dover's schedule, if adhered to, will not present difficult problems for complying with the FUA. The utility is interested in amendment or repeal of Title III regarding natural gas use in existing facilities; favoring continued use for the life of the facility or redefining the base period for gas use.

CASE STUDY NO. 4
WOLVERINE ELECTRIC COOPERATIVE, INC.
BIG RAPIDS, MICHIGAN
ERA REGION 18

1.0 System Description

1.1 Service Area and Customers

Wolverine Electric is a cooperative, generating and transmitting power to four member cooperatives who in turn redistribute the power to their residential, commercial, and industrial customers. Wolverine was formed in the late 1940's by these member cooperatives to meet their expanding needs.

The four distribution cooperatives are all located in central and southern Michigan, are all wholesale customers of Wolverine and account for all consumption apart from sales into the pool or to Consumers Power or the City of Lansing on an emergency basis.

Wolverine has ties to the City of Lansing, Michigan (through Consumers Power Company), from which they purchase some power when the generating costs are favorable and with the Michigan Power Pool through which they can buy, sell or trade electricity. Up to 25MW can be purchased from these sources on a non-firm six month contract.

1.2 Existing Facilities

There are five existing generating stations within the system and, with the exception of one combined cycle unit, all are internal combustion piston powered. The total generating capacity presently is from 72.7 to 79.7MW depending upon prevailing ambient temperatures. The higher rating is achieved in cold weather due to the inherent design features of internal combustion equipment. Table I describes the stations.

As will be noted, only five megawatts of the capacity are not on natural gas fuel, and these are diesel engines presently exempt from the Fuel Use Act (FUA). They are also peaking units.

1.3 Fuel Sources

Present supplies of natural gas are purchased from Michigan Consolidated Gas, Michigan Gas Utility, by pipeline, and from some small local fields. None of the contracts extend to 1990 or beyond.

1.4 Demand Projections

The system growth rate has been projected at 3.5 percent per annum from a 1979 level of 71 and 80.8MW summer and winter peaks, respectively. Table II illustrates this growth.

EXISTING UNITS

TABLE I

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	DUE ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
VanDyke	Burnips	2,4,5	INT.C.	Base	NO	4	1947,49	NG	284.2	Oil	9,800	NA
		6	CC-GT	Base		22-25	59,67	NG				
Johnson	Hersey	1-3	INT.C.	Base	NO	10	1947,48,	NG	414.0	Oil	11,833	NA
		4-6	G.T.	Peak		21-25	50,51,52	NG				
		7,8					73,73					
C.A. Winder	Port-land	1,2,3	INT.C.	Peak	NO	4	1950,48,	Oil	42.0	-	10,500	NA
		4,5					46,41,41					
Scott-ville	Scott-ville	1-3	INT.C.	Peak	NO	1	1941	Oil	52.5	-	10,500 (est.)	NA
		4-6	INT.C.	Base		4	1947,61	NG		Oil		
Vesta-burg	Vesta-burg	2,4,5	INT.C.	Peak	NO	2	1939,41	NG	76.6	Oil	10,500	1 & 3 (1990)
		6,7	INT.C.	Base		6	1959,60	NG				NA

Average system generating capacity = 72.7 - 79.7 MW

TABLE II. PROJECTED GROWTH RATE

YEAR	Summer Peak (MW)	Winter Peak (MW)
1979	71.0	80.8
1980	73.5	83.6
1985	87.5	99.2
1990	104.0	117.9
1995	123.5	140.0
2000	146.7	166.3

Future power suppliers will require that a reserve margin of 20 percent of the purchased power be kept available, and Wolverine's existing system will serve to meet the requirement. Wolverine has purchased 10MW of Campbell III from Consumers Power, and that unit is due commercial at this date. This is a coal-fired 770MW unit. Future needs will also be met with power from Detroit Edison's 1,215MW Enrico Fermi II nuclear reactor in which they have purchased a 7.78 percent share. Nuclear-generated power should be available by early 1983 from this unit.

A third source of future supply may be in the form of a wood and municipal refuse-fueled plant jointly owned by Consumers Power and Wolverine. A feasibility study has returned positive results and the power companies are presently dealing with local and Federal government agencies with regard to siting and funding. The proposed unit would be rated at 25MW and might burn a mixture of refuse-derived fuel and wood chips from the abundant forests of Michigan. There are societal and economic obstacles presently involving construction of this facility, but the partners apparently intend to build the plant in which they have already invested $1 million in exploratory funds. Table III presents capacity under construction and proposed.

2.0 Fuel Use Act Implications

2.1 Compliance Strategies

The FUA has had little or no impact on plans for future expansion by Wolverine. To meet near-term future demand, Wolverine owns 10MW of a 770MW coal-fired powerplant being built by Consumers Power (an IOU) and due to come on line late this year or early in 1981. For later growth, Wolverine owns 7.78 percent of Fermi II, a nuclear plant primarily owned by Detroit Edison and due to come on line in 1982 or 1983. This will provide as much as 96MW, which should be adequate for Wolverine growth anticipated through 2000. The growth rate assumed by Wolverine is 3.5 percent based on recent experience. It is anticipated that the present gas-fired capacity will go into peaking service after 1990, and that permanent exemptions will be sought to continue to use gas for peaking. No difficulty is anticipated with obtaining those exemptions.

3.0 Joint Ownership

In Michigan, a joint action bill was passed two years ago, and at the present time, two groups of municipalities have formed joint action agencies. Wolverine was asked to sit with one of these groups as they were forming, but decided, based on those meetings, not to participate in any possible agency. The main reason for this decision was that the municipalities were perceived as being unable to make decisions fast enough, since it was necessary that any decision be taken back to a city council or equivalent before it could be approved.

Joint ownership, however, is very actively pursued and is the foundation of Wolverine's compliance strategy. Wolverine considered that one characteristic of their joint ownership was unusual and worthy of mention. That was a provision to sell back to the other owners any power from an operating facility which was not used by one of the owners. In this way, Wolverine is not faced with having more power than they can use economically.

Wolverine identified two reasons for joint ownership being attractive to small utilities. First, it is difficult to justify a small, conventionally-fueled powerplant because the per kilowatt cost of a large plant is so much less. Secondly, there is a problem with a shortage of financing, and the cost of capital, especially for an IOU. Hence, they seek participation by coops and municipals which have fewer financing difficulties. Joint-planning committees have been operating in Michigan for both generation and transmission planning. Joint ownership of transmission facilities is also planned.

In addition to the coal and nuclear capacity which is being added, Wolverine is involved in a joint venture with Consumers Power to build a wood and RDF-fired 25MW boiler in Hersey, Michigan. They have sought DOE support for planning this unit under the synfuels initiatives program, but were told the unit would not qualify as a synfuel facility. They continue to plan the facility, including seeking permits and preparing an Environmental Impact Report, and claim that construction will proceed even if Federal support is not provided. However, this unit is not included in Wolverine's planned capacity which was provided us. The reason given for this omission was that uncertainty with the start-up date for the wood/RDF unit was too great. We did not find out what fraction of the wood/RDF unit was owned by Wolverine. The use of RDF in the plant is being opposed locally in Hersey because of fear of air pollution and rodent problems. A town council vote on the plant was being sought during the week of May 5.

Table III describes the coop's joint action projects, proposed and under construction.

4.0 Conclusions

Wolverine's primary source of information on the FUA is the NRECA. System Manager, John Keen, is very active in NRECA, and consequently is kept well informed by them on requirements of the Act as well as strategies for compliance. ERA provides some information on the FUA, but their information is usually several weeks to several months tardy due to the requirements of the bureaucracy. NERC has a weekly newsletter which provides the most up-to-date information. ECAR also provides some information on FUA matters, but Mr. Keen does not think that source is as available to everyone. He is on an ECAR committee, and considers that most of his information is from the committee, hence not available to all utilities in ECAR.

PROPOSED UNITS

TABLE III

STATION NAME	UNIT	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	RATED CAPACITY	DUE ON-LINE COMMERCIALLY	PREFERRED FUEL	ALTERNATE FUEL	HEAT INPUT RATE	MAXIMUM HEAT RATE	RETIREMENT DATE
J.H. Campbell (Consumers Power Co.)	3	Steam	Base	NO	770*	1980	Coal	None	NA	10,000	NA
Fermi (Detroit Edison)	2	Steam	Base	NO	1215**	1982/83	Uran	None	NA	NA	NA
Hersey, Michigan***	NA	Steam	Base	NA	25	1984/85	Wood & RDF	NA	NA	NA	NA

* Wolverine owns 10 MW.

** Wolverine owns 96 MW

*** Proposed in conjunction with Consumers Power Company.

Wolverine considers that its most serious problems with compliance with the FUA are in completing the paperwork. They have had no problems with the exemptions sought so far (for use of gas between now and 1990), and anticipate no problems in the future. Wolverine agrees with the objectives of the FUA, as is evidenced by their movement to coal and nuclear before the FUA was passed.

With projected capacity additions through joint ownership, all of Wolverine Electric Cooperative's existing capacity will be on peaking and/or standby service by 1990. This will permit them to be in compliance with the FUA provided they are able to obtain peaking exemptions. Since the planning which allowed them to comply was done prior to the passage of the Act, the Act has only had the effect of increasing their paperwork.

CASE STUDY NO. 5
CENTRAL TELEPHONE AND UTILITIES
(WESTERN POWER DIVISION)
GREAT BEND, KANSAS
ERA REGION 21

1.0 System Description

1.1 Service Area and Customers

CTUWPD provides electric service to 144 communities in central Kansas. Table I depicts the mix of customers and rate of consumption of the present CTUWPD system. The figures presented are for the year ending March 31, 1980.

CTUWPD's wholesale customers include 11 rural electric coops who are collectively responsible for approximately one-third of CTUWPD's total peak demand. These wholesale customers have formed an umbrella or super-coop known as Kansas Electric Power Cooperatives (KEPO) with the intent of becoming their own power supplier. KEPCO is presently in the process of seeking approval as a generation and transmission cooperative to serve its wholesale customer members. Thus, a substantial portion of CTUWPD's present wholesale customer may be in the process of becoming a competing utility. KEPCO is seeking required certification from the Kansas Corporation Commission.

TABLE I. CUSTOMERS AND CONSUMPTION

	No. of Customers	Energy (MWh/yr)*
Residential	49,723	356,916
Commercial	12,309	357,021
Industrial	83	357,075
Other (coops, other utilities, etc.)	307	666,957
	62,422	1,737,969

* Year ending March 1980.

1.1 Existing Facilities

CTUWPD's wholly-owned electric generating capacity consists of nine generating units located at four generating stations detailed in Table II.

Not included in the table are five generating stations and two additional generating units (at Judson Large), all of which had been retired January 1, 1980. The retired plants consisted primarily of diesel units which were not covered by the FUA, but which were retired due to their age and increasing operating and maintenance expenses.

Also not included in Table II is CTUWPD's joint ownership in each of the four coal-fired steam turbine generators at the Jeffrey Energy Center at St. Mary's, Kansas. CTUWPD owns an eight percent interest in each of the four units planned for the Jeffrey Energy Center, with each unit rated at 688MW net capacity. The remaining participation in the Jeffrey Energy Center is divided as follows:

Kansas Power and Light (KP&L)	64 percent
Kansas Gas and Electric (KG&E)	20 percent
Missouri Public Service (MPS)	8 percent

EXISTING UNITS

TABLE II

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
Arthur Mullergren	Great Bend	1	Steam	Base	NO	18	1953	NG	234	Oil	13,600	NA
"	"	2	Steam	Base	NO	18	1955	NG	234	Oil	13,000	NA
"	"	3	Steam	Base	NO	93	1963	NG	1023	Oil	11,000	NA
Judson Large	Dodge City	3	Steam	Base	NO	18	1957	NG	234	Oil	13,400	NA
"	"	4	Steam	Base	NO	143	1969	NG	1630	Oil	11,400	NA
Clifton	Clifton	1	Turbine	Peak	NO	70	1974	Oil	NA	None	NA	NA
"	"	2	Piston	Peak	NO	3	1974	Oil	NA	None	NA	NA
Cimarron River	Liberal	1*	Steam	Base	YES**	60	1963	NG	744	None	12,400	NA
"	"	2*	Turbine	Peak	--	14	1963	NG	224	None	16,400	NA

* Operates as combined cycle unit for peaking service.

** Steam is supplied to nearby National Helium Corporation.

KP&L operates and maintains the Jeffrey Energy Center. Currently, Units No. 1 and No. 2 are in service. CTUWPD owns 55MW each, a present total of 110MW capacity. It is the completion of Jeffrey Energy Center Units No. 1 and No. 2, providing base load, which has enabled CTUWPD to retire its older diesel Powerplants, above.

Jeffrey Energy Center Units No. 3 and No. 4 are scheduled for commercial operation in June 1983 and June 1985, respectively.

CTUWPD's wholly-owned capacity totals 437MW but some of the units are used for peaking only, while others are on standby.

1.3 Fuel Sources

CTUWPD has no contracts for fuel supplies which extend beyond 1990.

The Mullergren station receives its natural gas from KP&L on a one-year cancellation contract.

The Cimarron River plant is supplied by Anadarko Gas and this contract has a minimum purchase clause. Seventy-five percent of their daily allowance of 19, 000 mcf (thousand cubic feet) has to be purchased on a "take-or-pay" basis. In 1983, the daily allowance under this contract will automatically reduce to 5,000 mcf per day, if such an amount is available then.

Judson Large receives gas from both Cities Service and Peoples (Division of Northern Natural Gas). The Cities Service contract can be cancelled on 30 days notice.

Since 1979, CTUWPD has had no fuel oil contracts in effect and has become a spot market purchaser. Heavy fuel oil (No. 5) is used at both the Mullergren and Judson Large stations. There is no fuel oil capability at Cimarron River which is 100 percent dependent on natural gas supplies. CTUWPD is not an owner of any gas wells or other fuel sources.

1.4 Demand Projections

Given the unusual and substantial uncertainty facing CTUWPD as a result of KEPCO's creation and the proposed withdrawal of wholesale customer coops, it is very difficult for CTUWPD planners to project their demand beyond the short term. Table III presents their best estimate. It is based on the retention of KEPCO members in their present capacities as CTUWPD wholesale customers. The projected growth rate through the year 2000 is approximately 3.5 percent annually.

2.0 Fuel Use Act Implications

2.1 Applicability

CTUWPD's 3.0MW of oil-fired piston engine generating capacity is not subject to the FUA.

All other CTUWPD powerplants will be required to comply with the FUA under Titles II, III, or V. Mr. Earl Rhodes, Manager for the Western Power Division, indicated that much of CTUWPD's effort to decrease reliance on natural gas and to increase their usage of coal was based not on the FUA, however, but rather on economic factors. The CTUWPD decision to participate in the Jeffrey Energy Center, which now has two 688MW coal-fired units on-line, was made well in advance of the Jeffrey Energy Center has eased CTUWPD's problems in FUA compliance somewhat, but, as will be discussed in the remainder of this case study, that decision has not solved all of the utility's problems under the Act with respect to existing facilities. One impact that results from both the economics of coal

TABLE III
WESTERN POWER DIVISION, CENTRAL TELEPHONE AND UTILITIES CORPORATION, PROJECTED GROWTH AND SOURCES OF POWER SUPPLY

	SYSTEM LOAD NET 1 HOUR	FIRM PURCHASES (MINUS)	(1) FIRM SALES (PLUS)	TOTAL SYSTEM PEAK RESPONSIBILITY	REQUIRED RESERVE (15% OF ITEM 5)	RESPONSIBILITY	ACCREDITED GENERATING CAPACITY	CAPACITY SALES (MINUS)	CAPACITY PURCHASES (PLUS)	TOTAL SYSTEM CAPACITY	CAPACITY BALANCE
1980	429	--	42	471	71	542	546 (2)	25 (7)	130 (3)	651	+ 109
1981	444	--	45	489	73	562	546	50	130	626	+ 64
1982	459	--	47	506	76	582	546	50	130	626	+ 44
1983	475	--	50	525	79	604	600 (4)	50	130	680	+ 76
1984	491	--	53	544	82	626	600	25	130	705	+ 79
1985	508	--	56	564	85	649	654 (5)	--	130	784	+ 135
1986	526	--	60	586	88	674	654	--	130	784	+ 110
1987	545	--	63	608	91	699	654	--	130	784	+ 85
1988	564	--	67	631	95	726	654	--	130	784	+ 58
1989	583	--	70	653	98	751	654	--	130	784	+ 33
1990	604	--	74	678	102	780	654	--	130	784	+ 4
1991	625	--	77	702	105	807	654	--	130	784	- 23
1992	647	--	81	728	109	837	654	--	130	784	- 53
1993	670	--	85	755	113	868	829 (6)	--	---	829	- 39
1994	694	--	89	783	117	900	829	--	---	829	- 71
1995	718	--	94	812	122	934	1,004 (6)	--	---	1,004	+ 70
1996	743	--	98	841	126	967	1,004	--	---	1,004	+ 37
1997	770	--	103	873	131	1,004	1,179 (6)	--	---	1,179	+ 175
1998	797	--	109	906	136	1,042	1,179	--	---	1,179	+ 137
1999	825	--	114	939	141	1,080	1,179	--	---	1,179	+ 99
2000	855	--	120	975	146	1,121	1,179	--	---	1,179	+ 58

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(1) CKEC and Generating Municipals
(2) Add Jeffrey #2 + 54; Derate - 8; Rerate + 3; Retire - 33
(3) KP&L + 130
(4) Add Jeffrey #3 + 54
(5) Add Jeffrey #4 + 54
(6) Add 175MW unit (3 - Hypothetical units to meet requirements)
(7) Participation sale to Sunflower Electric Corporative (SEC)

technologies and the requirements of the FUA is an increased interest in joint ownership projects such as the Jeffrey Energy Center. Mr. Rhodes indicated that he expects all foreseeable future projects of CTUWPD to involve participation in joint ownership projects.

2.2 Compliance Strategies

2.2.1 Existing Facilities

With respect to its existing gas-fired facilities, CTUWPD has bascially four options in complying with the FUA's prohibitions:

- Fuel conversion (oil or alternate fuels);
- System compliance option;
- Permanent and/or temporary exemptions; and
- Plant closures or sale of equipment/purchase of supplemental power.

Fuel Conversion: Seven out of nine existing CTUWPD generating units, including the three largest, are capable of using oil without extensive modifications. This is not, however, considered an attractive compliance strategy both because of projected additional costs of fuel and because of the possibility of "oil backout" legislation. CTUWPD did not consider converting to oil as a likely long-term solution to the FUA prohibitions.

CTUWPD has considered conversions and partial conversions to alternate fuels. They commissioned feasibility studies of Black and Veatch Consulting Engineers in 1977. The studies were commissioned at that time not in response to the FUA, but to the scarcity and rising costs of oil and natural gas. Mr. Rhodes indicated that the studies were "very discouraging," indicating substantial problems with site limitations, transportation costs, and loss of capacity on existing units.

Mr. Rhodes indicated that CTUWPD is actively pursuing a proposal to install a central tower and heliostats to Cimarron River station. Black and Veatch assisted as consulting engineer in the preparation of a proposal to DOE. The Cimarron River station is currently involved in cogeneration activities, providing steam to the National Helium Corporation in Liberal, Kansas.

System Compliance Option: One of the two principal compliance strategies being pursued by CTUWPD is the system compliance option authorized under Title V of the Office of Fuels Conversion, Economic Regulatory Administration, Department of Energy, complying with the minimum requirements for plan submission. The effect of the letter was to inform the Office of Fuels Conversion of CTUWPD's intent and to reserve the CTUWPD the right to submit a detailed compliance plan. CTUWPD did file a system compliance plan to August 1, 1980.

Office of CTUWPD have met with DOE officials on two occasions to discuss the system compliance option as it may apply to CTUWPD. Following the second meeting in Denver on April 3, 1980, the utility hired Black and Veatch to assist in the preparation of a detailed system compliance plan for August 1, 1980, submission.

Central Telephone and Utilities Corporation has two divisions operating as electric utilities. One is the Southern Colorado Power Division; the other (Western Power Division) is in Kansas. The two operating divisions are not separate corporations, but rather they are operated as divisions within the same corporation. They are not physically interconnected, as through transmission lines.

CTUWD has a special problem with regard to its largest wholly-owned generating unit: Judson Large Unit No. 4. The 143MW generating unit burned

58 percent gas and 42 percent oil during the base period of 1976, although historically it has fired, more typically, 95-98 percent natural gas. The effect of the historical anomaly of low gas usage by the largest unit in the base period could result in a disadvantageously low natural gas allotment under an approved system compliance plan. Natural gas use could be limited to 20 percent of base year usage.

FUA 501(e)(2)(B) provides some flexibility for the Secretary of Energy to allow a percentage of base year usage larger than 20 percent upon a demonstration that such higher percentage is necessary "because it would not be feasible for such utility to comply....without impairing reliability of service." The apparent flexibility may or may not be of practical consequence on the facts to be presented. Additional capital and fuel expenditures may be viewed as alternatives open to the utility to provide desirable reliability while staying within 20 percent of base year natural gas allocation.

Another alternative for the Judson Large No. 4 Unit is to secure an exemption for that facility.

Permanent and/or Temporary Exemptions: Exemptions are the second principal compliance strategy being pursued by CTUWPD. It may be possible to obtain an exemption for a particular generating unit or units and to obtain approval for a system compliance plan covering the remaining units. An exemption might be obtained for Judson Large No. 4 and a system compliance plan approved for all other CTUWPD generating units.

Problems arise in following this strategy, however, because of two critical legal points

- Under FUA 501(a), "No exemption...will be available for any powerplant which is, or has ever been, covered by such an approved plan..." The thrust of this provision is that an exemption can only be obtained prior to the approval of a system compliance plan. Plan approval cuts off all exemption alternatives (other than for emergencies).
- The second critical legal point is that there is no mechanism by which a utility may assure itself of a decision by DOE on its exemption request at a point in time prior to DOE's decision on the approval of a system compliance plan. If CTUWPD files both a request for an exemption for Judson Large No. 4, and a system compliance plan, no matter the order or timing of the separate petitions, there is no mechanism for the utility to be assured of a timely decision on the exemption request before the approval of the system compliance plan forever cuts off the exemption options. FUA 411(c)(4) has been interpreted as prohibiting the establishment of procedures which would prioritize the DOE decision-making process so that utilities may obtain decisions on their exemption petitions approved. Section 701 reads as follows: "Any order for the approval of a system compliance plan under Section 501 of this title, and any petition for such an order, shall be treated for purposes of this subchapter the same as an order (or petition) for an exemption."

The strategic problem just described is a source of grave frustration for CTUWPD and other utilities who in general, will incur substantial consulting or in-house expenses in preparing to seek exemption approval. Although frustrating, this situation will not deter CTUWPD from pursuing the exemption and system compliance strategies, in tandem. CTUWPD has asked Black & Veatch to examine exemption options and to prepare appropriate petitions for filing.

On April 1, 1980, CTUWPD filed a petition for temporary public interest exemption for the use of natural gas in five of its generating units:

- Arthur Mullergren Station, Unit No. 1;

- Arthur Mullergren Station, Unit No. 2;
- Arthur Mullergren Station, Unit No. 3;
- Judson Large Station, Unit No. 3; and
- Judson Large Station, Unit No. 4.

Among the permanent exemption alternatives being carefully considered by CTUWPD and its consultant, are the following:

- Peak load unit exemption;
- Intermediate load unit exemption;
- Site limitations exemption (especially as applied to Judson Large Station, Units No. 3 and No. 4); and
- Lack of alternate fuels.

2.2.2. New Capacity

The Jeffrey Energy Center Units No. 3 and No. 4 are examples of new units scheduled to go on-line to assist CTUWPD in future FUA compliance. These two base load coal-fired units will provide 688MW each, of which CTUWPD will have eight percent. They are scheduled for 1983 and 1985, respectiviely, although knowledgeable sources believe project timing may slide.

3.0 Joint Ownership

CTUWPD's primary interest in new units would be through the pursuit of joint ownership projects following the Jeffrey Energy Center model. Participation in such projects makes it possible for CTUWPD to utilize large scale state-of-the-art technologies while investing in moderate increments of additional capacity consistent with system size and growth.

4.0 Purchased Power

In addition to its eight percent ownership interest in each of the four Jeffrey Energy Center units, CTUWPD also has a contract for the purchase of power from KP&L interest in Units No. 1 and No. 2. KP&L has agreed to provide 65MW to CTUWPD from each of the two units (a total of 130MW) through May 31, 1993.

5.0 Conclusions

CTUWPD officials showed themselves to be knowledgeable and resourceful in their efforts to comply with the FUA. Among small utilities, they seem, as a result of their foresight in participating in the Jeffrey Energy Center, to be relatively able to comply until 1993. Their overall objectives are to bring on-line new coal-fired powerplants in which they are joint ownership participants; to purchase supplemental power through the critical period until 1993; and to downgrade much of their existing wholly-owned capacity to peak and intermediate load purposes. They are encountering a relatively narrow range of problems, as compared to other, less knowledgeable small utilities, and they seem likely to manage those problems successfully. They are, however, incurring substantial costs in FUA compliance, including:

- Consulting and legal fees;
- Staff time; and
- Capital costs to achieve compliance.

In terms of their options to pursue either exemptions or a system compliance plan under the RUA, their decision is to pursue both for as long as they can until forced to decide between competing options. For the present, they feel that the regulatory situation created by the statute and by DOE regulations is hopelessly muddied and ambiguous. Rather than choose between significant options which they see as inadequately defined, they will keep their options open for as long as possible. Their view is that perhaps, in time, enough information will be available to permit an intelligent economic decision.

The closure or sale of plants unable to comply with the FUA and the purchase of supplemental power is an option to CTUWPD on a case-by-case basis. Through 1993, the purchase of power under contract (130MW from KP&L) plays an important role in CTUWPD's compliance strategy. Whether it is a role that may expand in the later 1990's is problematical at best. It is an option that CTUWPD will continue to evaluate both separately and in tandem with its interest in future joint ownership ventures.

CASE STUDY NO. 6
SIERRA PACIFIC POWER COMPANY
ERA REGION 28

1.0 System Description

Sierra Pacific is a small investor-owned utility which serves an approximate 43,000 square mile area of north and central Nevada and eastern California. Sierra Pacific supplies electricity to 128,465 customers in northern and central Nevada and 34,433 customers in Northeastern California. The company also sells electricity to seven utilities located in the western states. In addition to these electric sales, Sierra Pacific furnishes retail natural gas service to 50,848 customers and water service to 41,388 in Reno and Sparks, Nevada.

Table I identifies the system composition of retail customers and their consumption rates.

TABLE 1 - Customers and Consumption (as of 12/31/79)

	No. of Customers (yr. end)	Energy MWh
Residential	139,793	1,054,745
Small Light & Power	57,756	1,240,999
Large Light & Power	21,529	584,553
Public Street & Highway	1,363	15,507
Other Sales to Public Authorities	180	3,984
Total	162,931	2,899,788

1.2 Existing Facilities

Sierra Pacific's total generating capacity was 564,200KW as of 12/31/79. Approximately 31 percent of the energy produced by the company generators was fueled with oil, 67 percent with natural gas and two percent by small hydro plants.

The fuel mix configuration changed significantly as of February and March 1980 because of a substantial increase in the price of natural gas. Currently the utility's fuel mix is 70 percent oil and 30 percent natural gas.

Sierra Pacific's generating configuration consists of 1.7MW of hydro; 50MW of internal combustion units; 36.5MW of gas turbines; and 466MW of conventional steam units. The internal combustion units are fueled by Bunker "C" oil. The gas turbines and conventional steam units are dual fuel-fired units capable of burning either oil or natural gas.

Table II describes the existing and planned plant equipment in detail.

1.3 Fuel Sources

Sierra Pacific currently obtains its natural gas supply from the Southwest Gas Corporation (Southwest). Sierra Pacific's contract with Southwest is anticipated to expire on November 1, 1987. The contract contains a take or pay clause therefore, Sierra Pacific must consume a minimum of 8716 mm thms. annually or incur a penalty. Sierra Pacific is typically restricted on gas use during the winter months.

Sierra Pacific initiated a five year oil contract with the Western Refining Company of Utah in May of 1979. In addition, Sierra Pacific buys oil on the spot market from the Golden State Petroleum and the Nevada Refining companies as required.

EXISTING UNITS

TABLE II

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
Tracy	Wunatoo	1	Steam	Peak	NO	53	NA	Oil	$.65.10^9$	NG	12,220	1993
		2	Steam	Peak	NO	83	NA	Oil	$.92.10^9$	NG	11,080	1995
		3	Steam	Base	NO	110	NA	Oil	$1.13.10^9$	NG	10,300	2004
Fort Churchill	Wabuska	1	Steam	Base	NO	110	NA	Oil	$1.13.10^9$	NG	10,300	1998
		2	Steam	Base	NO	110	NA	Oil	$1.13.10^9$	NG	10,250	2001
North Valmy	Valmy	1	Steam	Base	NO	238	1981	Coal	$2.03.10^9$	None	9,531	2011
		2	Steam	Base	NO	267	1984	Coal	$2.63.10^9$	None	9,837	2014
Winnemucca		1	Turbine	Peak	NO	13.9	NA	Oil	--	Gas	--	--
Tracy		-	Turbine	Peak	NO	22.6	NA	Oil	--	Gas	--	--
Valley Road		-	Int. Comb.	Peak	NO	6	NA	Oil*	--	--	--	--
Brunswick		-	"	Peak	NO	6	NA	Oil	--	--	--	--
Battle Mtn		-	"	Peak	NO	8	NA	Oil	--	--	--	--
Portola		-	"	Peak	NO	6	NA	Oil	--	--	--	--
Lahontan (L)		-	"	Peak	NO	2	NA	Oil	--	--	--	--
Fallon		-	"	Peak	NO	2	NA	Oil	--	--	--	--
Kings Beach		-	"	Peak	NO	16.5	NA	Oil	--	--	--	--

EXISTING UNITS

TABLE II CONT.

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	DUE ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
Gabbs		-	Int. Comb.	Peak	NO	5.5	NA	Oil*	--	--	--	--
Farad		-	Hydro	Peak	NO	2.6	NA	--	--	--	--	--
Fleish		-	Hydro	Peak	NO	2.5	NA	--	--	--	--	--
Verdi		-	Hydro	Peak	NO	2.1	NA	--	--	--	--	--
Washoe		-	Hydro	Peak	NO	1.8	NA	--	--	--	--	--
Lahontan (L)		-	Hydro	Peak	NO	2.7	NA	--	--	--	--	--

* Internal combustion units on Bunker "C" fuel.

L Leased

1.4 Demand Projections

Table III shows Sierra Pacific's peakload demand is projected to double by 1990. This assumes an annual growth rate of approximately seven percent.

The table shows that a large growth rate is occurring primarily in the first few years. This is due to step load changes that take place as a result of mining activity that has been committed in the 1980 and 1981 periods.

TABLE III

Sierra Pacific Power Company Demand

Year	Average Demand (MW)	Peak Net Generation (MW)
1979	410	574
1980	440	649
1981	489	711
1982	524	756
1983	553	797
1984	584	839
1985	614	880
1986	646	924
1987	677	968
1988	710	1015
1989	744	1062
1990	779	1112

2.0 Fuel Use Act Implications

2.1 Applicability

With the exception of 11.7 MW of hydro and 50 MW of internal combustion capacity, all of Sierra Pacific's base load and intermediate load units are, pursuant to Title III of the Act, prohibited from burning natural gas in excess of that consumed during the 1974 through 1976 base periods.

Whether or not the FUA had been passed by the Congress in 1978, Sierra Pacific had indicated that it would have entered into a joint venture project with the Idaho Power Company providing for equal ownership (125 MW) in the Company's North Valmy Generating Station, and would have developed studies to determine the feasibility of converting an existing oil/natural gas fired plant to coal on the basis of economics.

2.2 Compliance Strategies

2.2.1 Existing Units

With respect to its baseload and intermediate load units, Sierra Pacific has primarily four options for complying with the FUA's prohibitions:

- Fuel conversion (oil or alternate fuels);
- System Compliance Option;
- Permanent and/or Temporary exemptions; and
- Sale of the system.

Fuel Conversion: Sierra Pacific has investigated the feasibility of converting its oil and natural gas fired Fort Churchill plant to coal. Preliminary indications are that a substantial de-rating will be required and the economics for coal conversion are questionable. Capital costs are estimated at $168 million to convert a $30 million plant. Sierra Pacific states that one half of the costs will be required for pollution abatement equipment.

The company is also investigating the feasibility of converting one of its oil and natural gas-fired generating units to solar power under a grant from the Department of Energy. This project is a joint venture with the McDonnell Douglas Corporation.

Sierra Pacific has joined four other companies in assessing northern Nevada's geothermal resources, applicable plant types and legal regulatory requirements.

These activities are focused on establishing a model electric generating plant powered by steam from one of Nevada's hot water resources. The assessment of sites for this plant will be completed in the near future.

System Compliance Option: Sierra Pacific has notified DOE of its intent to utilize the system compliance option, thereby complying with the minimum requirements for plan submission. The effect of the letter was to notify DOE's Office of Fuels Conversion of Sierra Pacific's intent and to reserve the right to submit a detailed plan.

If Sierra Pacific does submit a plan and it is subsequently approved, the company must adhere to certain parameters listed below, unless otherwise negotiated.

- Between 1980 and 1990, the company shall not use more natural gas in any of the existing powerplants in its system in greater proportion than it used in the 1974 through 1976 base period. However, a higher percentage may be allowed if the utility can demonstrate to the satisfaction of DOE that because of delays which occurred despite diligent good faith efforts, in the construction of alternate fuel-fired powerplants; and if a higher percentage were not allowed, reliability of service would be impaired;
- On or after January 1, 1990, the company will not use natural gas in any of the existing powerplants in its system in excess of 20 percent of its base period usage or, if lower, minimum peak load requirement for the calendar year;
- From 1995 to 2000, the company will not use gas as a primary energy source, except for intermediate load and peak load and;
- On or after January 1, 2000, the company will not use natural gas in any of the existing powerplants in its system, except in cases where a temporary extension is obtained.

Permanent and/or Temporary Exemptions: Sierra Pacific states that the FUA does not apply to all of its units. Due to case by case application of the interim regulations it is difficult to determine whether FUA applies to any of its units.

Sierra Pacific has petitioned ERA for a special temporary public interest exemption for Tracy units 1, 2 and 3 and at Fort Churchill units 1 and 2. If granted the exemption will allow Sierra Pacific to displace the consumption of No. 6 fuel oil.

Sierra Pacific does not plan to file petitions for permanent exemptions at this time.

Sale of System: Sierra Pacific does not consider the sale of its generation and transmission facilities to a larger utility as a viable alternative to compliance with FUA.

2.2.2 New Capacity

Sierra Pacific was well aware of the need for long range planning prior to the passage of FUA. The company recognized that prudent forecasting was essential to meet the future needs of its customers. Such planning is done by employing its own computerized econometric model, sophisticated site selection for future powerplants and ongoing resource availability studies. The economic model projects customer's peak demands and sales information. This data is used to forecast construction, fuel and purchased power requirements and operating costs.

Sierra Pacific has investigated the following options:

- Purchased power and;
- Construction of a jointly-owned plant based on an alternative technology

3.0 Joint Ownership

Sierra Pacific has joined four other utility companies in investigating the potential use of geothermal resources in northern Nevada. This investigation may ultimately lead to the joint construction of a 10MW generating plant powered by flashed steam from one of Nevada's hot-water reservoirs.

In December 1978, Sierra Pacific and Idaho Power Company entered into an agreement providing for equal ownership in the Company's North Valmy Generating Station. Each company will provide their own financing and share equally in all costs of construction.

North Valmy 1 and 2 are coal-fired units. Valmy Unit 1 is anticipated to be commercially available in September 1981 and will have a net generating capability of 238MW. Valmy unit 2 is projected to be commercially available in September 1984 and will have a net generating capability of 267MW.

Sierra Pacific has not investigated the possibility of joint action as a means of compliance with the FUA. The company does not know if there is enabling legislation in effect in Nevada that would allow two or more utilities to create a joint agency.

4.0 Purchased Power

Sierra Pacific currently purchases approximately 258,000KW through firm purchase agreements with Pacific Gas and Electric and Utah Power and Light Companies. However, declining reserve margins in the western states may result in the modification or cancellation of firm purchase agreements in order for those companies who currently have excess capacity to cover their own system requirements.

5.0 Conclusion

Sierra Pacific has recognized that prudent long range forecasting is essential to meet the future needs of its customers, maintain system reliability, and maintain flexibility necessary to meet changing political and economic environments.

The company has undertaken several aggressive programs to alleviate its reliance on foreign oil and natural gas. It has initiated studies to determine the plausibility of converting one of the existing oil/natural gas-fired facilities to either coal or solar; entered into a joint project with several other companies to investigate the feasibility and utiizing geothermal resources as a viable energy source in that region; and entered into a joint venture project with the Idaho Power Company to construct a 500MW coal-fired facility.

Sierra Pacific is concerned with the potential for conflict between the nation's energy, economic, and environmental policies. A small utility is presently caught between the need to provide its service at the lowest possible price, the desire to reduce dependence on foreign energy sources, and the desire to produce electricity with minimal effects on the environment. The Company feels that it is necessary to amend the Fuel Use Act and the National Environmental Policy Act to coordinate regulatory efforts in order to resolve these conflicts.

CASE STUDY NO. 7
VERO BEACH, FLORIDA
ERA REGION 7

1.0 System Description

1.1 Service Area and Customers

Vero Beach is located on the East Coast of Florida and is about 75 miles north of West Palm Beach. Vero Beach Municipal Electric System covers a service area of about 15 square miles serving the Cities of Vero Beach, Gifford, and Indian River Shores. Florida Power and Light, an investor-owned utility, surrounds the municipal system.

The service area boundaries are fixed through a territorial agreement between the utilities. Vero Beach is a retail power supplier with only one industrial customer, Piper Aircraft Company. Table 1 provides data on the number, classes, and consumption of the customers served. The data covers the period January 1, 1979, through December 31, 1979.

Table I. Customers and Consumption

	Customers	Energy -kwh/yr-
Residential	14,878	161,211,000
Commercial	2,468	126,249,000
Industrial	1	26,507,000
	17,347	313,967,000

1.2 Existing Facilities

The generating system of Vero Beach consists of four steam turbine units and five diesel units. The diesel units are the system's oldest units; the earliest unit, #2, having been installed in 1937, and the last unit, #6, in 1957. These units, which have a total net rating of 12.2MW, are now used for emergency and peaking power.

Currently, the four steam turbine units are used for base load requirements. The preferred fuel source is natural gas. However, units 1, 2, and 3 can burn #6 fuel oil with a 2.5 percent sulfur content and the fourth unit burns #4 fuel oil with a .7 percent sulfur content. In 1979, twice as much natural gas was used as a fuel source as oil. The units supply all Vero Beach's power needs at this time which includes purchases and sale through economy interchange. Table II describes the units in detail.

1.3 Fuel Sources

Vero Beach has relied on two companies for its fuel supplies: Florida Gas Transmission Company for natural gas and Belcher Oil for oil needs. Currently, Vero Beach has an interruptible natural gas contract which is due to expire in 1985. Whether the contract can be renewed and at what price is still difficult to determine at this time.

The amount of natural gas that the utility purchases is limited by the capacity of the pipeline through which the fuel source is delivered. The pipeline can transport only up to 45MW of natural gas generating capacity. According to utility officials, adding pipeline capability would not, in normal times, be a

EXISTING UNITS

TABLE II

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE* (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE** (BTU/KWH)	RETIRE-MENT DATE
17th Street	Vero Beach	1	Steam	Base	NO	12	1961	NG	188	Oil	17,400	1992
"	"	2	Steam	Base	NO	16	1964	NG	231	Oil	14,500	1995
"	"	3	Steam	Base	NO	30	1971	NG	429	Oil	13,800	2001
"	"	4	Steam	Base	NO	52	1976	NG	605	Oil	12,200	2006
Vero Beach		1	Diesel	Peak	--	1.15	1947	Oil	19***	None	-	1985
"		2	Diesel	Peak	--	.75	1937	Oil	19	None	-	1985
"		4	Diesel	Peak	--	4	1952	Oil	61	None	-	1985
"		5	Diesel	Peak	--	3.9	1953	Oil	61	None	-	1985
"		6	Diesel	Peak	--	5.4	1957	Oil	56	None	-	1985

* Heat input rates are based on nameplate rating.

** Maximum Heat Rate occurs at minimum load.

*** Maximum heat input rate listed for diesel units.

problem, except that now under the Fuel Use Act with the definite mandate to reduce consumption of natural gas, suppliers of this fuel source are obviously reluctant to finance such a capital venture.

1.4 Demand Projections

Vero Beach has experienced a high growth rate during the last ten years, averaging seven to nine percent per year which is expected to continue until 1985. From 1985 to 2000, a four to six percent annual growth rate is estimated. The estimates are greater than the expected average for the State of Florida and for surrounding areas such as Dade County. With increasing social and economic problems in some of the Florida counties, Vero Beach is attracting more tourists and residents, expecially retired persons. Table III contains detailed data on demand estimates.

Table III. Projected Demand

Year	Annual Energy (net kwh)	Peak Load (MW)
1979	350,000,000	78
1980	368,000,000	99
1985	583,000,000	115
1990	703,000,000	114
1995	855,000,000	176
2000	1,040,000,000	214

2.0 Fuel Use Act Implications

2.1 Applicability

The four steam turbine units in the Vero Beach system are each classified individually as an "existing electric powerplant" under the FUA definition. The units are base load with no one unit having a heat rate less than or equal to 100 million Btu/hr which does not exclude them from prohibitions under the Act.

The five diesel units, exempt under the Act, only operate when emergency power is needed and have a remaining limited life.

Of the 130MW generating capacity available to the utility, 117MW or 90 percent is represented by the four base load units which are not exempt under the Act. These units have dual fuel capability, i.e., they can burn either natural gas or fuel oil; natural gas being the preferred fuel based on economics and environmental reasons.

2.2 Compliance Strategies

Because of rapid electrical growth in Vero Beach, plans are currently being investigated for obtaining additional resources. It is generally recognized that by 1990 the current base load units will function as peak load units. The base load supply will be obtained by joint participation in large units and by firm power purchases from nearby utility systems.

Vero Beach's problems with the Fuel Use Act stems from the provision in Title III which permits utilities, from the inception of the Act to 1990, to burn only that portion of natural gas in their units which was used in the base

Expansion of the present site for a new unit is confined by its surroundings. The East side of the plant is located on the Indian River; to the South the plant borders a new bridge as well as a residential area; and to the North and West the plant is surrounded by private residencies. Vero Beach is also hampered by inadequate facilities to transport coal because of railroad access problems. The permanent exemption request is to allow Vero Beach to burn unrestricted amounts of natural gas until 1990. After 1990, the utility could then convert its existing units to peaking and intermediate load service.

The Vero Beach utility is very anxious for a permanent exemption to be considered expeditiously before a decision is made on the system compliance option in order not to be precluded from exemptions if the system compliance option is granted.

System Compliance Option: The City plans to apply for a system compliance option before the August 1980 deadline. The type of compliance is currently being drawn up by the City's attorneys. Again, the City would prefer a permanent exemption and is applying for a system compliance option as a contingency.

Sale of System: Vero Beach is willing to sell its system and views it as a very attractive option. The idea of selling the system, however, is not a direct result of the FUA. In 1974, the City Council, along with the citizens of Vero Beach, voted to sell the municipal system to Florida Power and Light (FPL). A contract has been signed with FPL to purchase the system for 42.6 million dollars. The sale, however, was blocked by the Department of Justice and the FPC based on antitrust action alleging that Vero Beach was forced to sell, because it was denied access to needed transmission and generation plant capacity. Vero Beach respesentatives are very frustrated by the course of events, primarily because they believe they had correctly perceived the future problem on energy supplies recognizing that their system capacity was becoming inadequate and inefficient to meet demand, and that traditional fuel sources were becoming scarce and costly. Besides alleviating the energy source situation, the sale, according to City officials, would have been a windfall to the citizens of Vero Beach. Rates would have been up to 15 percent lower.2/ Approximately 15 million dollars would have been placed in a perpetual trust with interest earnings allocated to lowering taxes. And ad valorem taxes paid by FPL would have been added to city coffers. In addition, under the signed contract, employees of the municipal system were guaranteed jobs with the IOU at a higher salary. Although municipal officials still believe selling the system is a viable solution to the FUA, they realize that it would be almost impossible to get FPL to agree to do so again out of fear of becoming involved in another costly legal battle. Secondly, it is doubtful whether FPL would be interested in Vero Beach. The plant facilities, which were of minimum use in the 1974, would be a burden to the system because of the FUA.

3.0 Joint Ownership/Joint Action

A very obvious option for Vero Beach is to purchase a portion of a coal-fired or nuclear plant, either existing or under construction. Vero Beach has already been offered 8.34MW share of the St. Lucie 2 nuclear plant by FPL.

Vero Beach has hired the engineering consulting firm of Black and Veatch to prepare a bulk power supply study to determine the best fuel supply options for the City. The recently released study recommended that the utility pursue the St. Lucie 2 offer declining the purchase-sell back and nuclear reliability change options. It was suggested that Vero Beach monitor the costs of future coal units to determine the most economical joint participation possibility.

According to utility representatives, in all probability, the joint ownership options will be pursued through the Florida Municipal Power Agency (FMPA), a joint action agency set up in 1978. The enabling legislation permitting the establishment of a joint action agency was passed in 1975, but it was not until

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2/ Vero Beach's electricity rates are among the highest in Florida.

1979 that a bill was passed allowing the agency to issue tax-exempt bonds.

The factor which may inhibit Vero Beach's participation in FMPA is time. In addition to complying with the FUA regulations, the utility needs more capacity to meet growing demand by 1983. If FMPA has not negotiated for and received power within a reasonable time period to serve its members, Vero Beach will have to resort to seeking its own joint ownership participation. The utility is hesitant to pursue this path because of the expected difficulty in obtaining City Council approval of large bond issues to finance the ventures. The Black and Veatch report advocates continued membership in FMPA, but that prior to participating in a new unit, consideration be given to the possibility of higher costs due to FMPA debt coverage and agency fee estimates.

4.0 Purchased Power

Vero Beach expects to purchase firm power and already has a commitment from the FPL system in addition to possibilities with the Orlando municipal system. The Black and Veatch report recommends firm purchases from FPL. The amount of future purchases, though, is limited by the transmission interconnection. Even with the new 69kV loop, only up to 90MW can be tranferred.

5.0 Conclusions

Vero Beach faces a problem in complying with FUA. Compliance is a greater burden in the 1980 to 1990 period, then after 1990. During this time period, the utility is only permitted to burn less than half the natural gas it used in normal years, i.e., 25 percent based on the average of the base period (1974 to 1976) versus about 70 percent in other years from 1970 to 1980. (See Table IV.) Although the utility has a temporary public exemption until October 1981. Vero Beach will be forced to burn costly oil unless the exemption can be extended. Vero Beach supplies all its current power needs.

After 1990, the utility plans on obtaining future power needs from an optimum mix of sources including purchased power and jointly-owned units, which will result in decreasing its dependence on natural gas but not eliminating it completely. Consequently, the utility will need to burn natural gas or oil to supplement demand not offset by purchased power or joint participation. The utility prefers to use natural gas due to economics and environmental reasons.

In an effort to overcome the problem, the City is filing for a permanent exemption based on siting limitations and for a system compliance option.

TABLE IV
Vero Beach Municipal Powerplant
Oil and Natural Gas Burned
January 1, 1980-June 30, 1980

	Oil	Natural Gas	Natural Gas as a Percent of Total Fuel Use
1970	343,458	1,871,394	84
1971	91,366	2,337,085	96
1972	895,116	2,099,606	70
1973	1,235,094	2,040,213	62
1974	1,591,656	1,527,877	49
1975	2,526,006	688,704	21
1976	3,089,196	122,838	4
1977	2,211,876	1,380,358	38
1978	1,551,114	2,167,438	58
1979	1,307,910	2,055,100	70
*1980	597,288	1,845,893	76

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* 1980 - six months total

CASE STUDY NO. 8
LUBBOCK, TEXAS
ERA REGION 22

1.0 System Description

1.1 Service Area and Customers

Lubbock Power and Light (LP&L), a municipally-owned system, began operation in 1916 with the installation of one diesel generator. The system has since expanded to include three plants with a total generating capacity of 230MW. The service area encompasses approximately the 1977 city limits of Lubbock.

However, due to a unique situation, LP&L serves only about 50 percent of Lubbock's estimated 180,000 population. LP&L is in direct competition for customers with Southwestern Public Service Company (SPS), which serves the remaining Lubbock area customers. In addition, LP&L is presently constrained from expanding its service area outside the city limits, because it is bounded by other utility service areas.

1.2 Existing Facilities

LP&L power generating facilities are located at three plants. Table I describes the diesel engines, gas/oil-fired boilers and gas turbines that make up the system. Plant No. 1 is on emergency standby service only and does not ordinarily generate power except to maintain operating integrity of the plant. Unit 3 at Plant No. 2 is no longer in service due to a fire in 1977. All of the gas-fired boilers have the capability to dual-fire gas and No. 2 diesel (50 percent each). Holly Station Unit 2 can burn 100 percent diesel or No. 6 fuel oil, and is the only steam boiler capable of running on oil continuously. In addition, two of the three gas turbines located at the Holly Station can use diesel fuel.

All of the LP&L steam boiler units, except Unit 4 at Plant No. 2, swing with system demand. (With respect to the FUA they are "base load".) The Holly Station gas turbines and Plant No. 2's Unit 4 steam boiler are used to meet peak demands. All of the diesel engines are in standby service.

LP&L's present overall system heat rate is 12,500 Btu's per kWh. The two units at the Holly Station have average heat rates of 10,500-11,000 Btu per kWh while the older units at Plant No. 2 have heat rates of 15,000-16,000 Btu's per kWh. Presently, Tippett and Gee, as part of a large study, is reviewing the possibility of combining two of the gas turbines located at the Holly Station with two of the gas fired boilers at Plant No. 2 to make a combined cycle operation. This would significantly reduce the power generation heat requirements of LP&L system. No other plans exist for additional power generating capacity at this time to meet future power demands or the FUA. However, two studies are being done for LP&L addressing future needs. One study being conducted by Tippett and Gee will evaluate energy options for meeting future power demands and the FUA. The other study being conducted by Battelle is evaluating the use of municipal solid waste steam generation boilers for electric power generation at Plant No. 2. LP&L has also held discussions with several adjacent utility systems about joint ownership of a new coal-fired power generation unit but these talks have not progressed far.

1.3 Fuel Sources

LP&L presently obtains its natural gas supply from Pioneer Natural Gas. LP&L and Pioneer have a five-year renewable contract which is renegotiated every year for one additional year on the existing contract. LP&L is presently paying $2.40 per million Btu and expects the price of gas to increase by 3¢ per month over the next 18 months. LP&L fuel oil needs are met by

EXISTING UNITS

TABLE I

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	DUE ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
Plant #1	Lubbock	1	Diesel	Stand-By	--	2.25	1942	NG	NA	NA	NA	--
Plant #1		2	Diesel	Stand-By	--	.9	1929	NG	NA	NA	NA	--
Plant #1		3	Diesel	Stand-By	--	1.0	1932	NG	NA	NA	NA	--
Plant #1		4	Diesel	Stand-By	--	1.25	1934	NG	NA	NA	NA	--
Plant #1		5	Diesel	Stand-By	--	2.25	1940	NG	NA	NA	NA	--
Plant #2	Lubbock	1	Diesel	Stand-By	--	2.5	1946	Dual Fuel	NA	NA	NA	--
Plant #2		2	Diesel	Stand-By	--	2.5	1947	Dual Fuel	NA	NA	NA	--
Plant #2		3	Steam	--	--	7.5	1949	NG	NA	NA	NA	1977
Plant #2		4	Steam	Peak	--	11.5	1952	NG	NA	Oil*	NA	--
Plant #2		5	Steam	Swing	--	11.5	1953	NG	NA	Oil*	NA	--
Plant #2		6	Steam	Swing	--	22.0	1957	NG	NA	Oil*	NA	--
Plant #2		7	Steam	Swing	--	22.0	1958	NG	NA	Oil*	NA	--
Holly Ave.	Lubbock	HSI	Steam	Swing	--	44.0	1965	NG	NA	Oil*	16,000	--
		HSII	Steam	Swing	--	53.65	1978	NG	NA	Oil*	NA	--
		GTI	Turbine	Peak	--	12.5	1963	NG	NA	Oil*	NA	--
		GTII	Turbine	Peak	--	19.0	1971	NG	NA	None	NA	--
		GTIII	Turbine	Peak	--	20.0	1974	NG	NA	Oil*	NA	--

*Diesel

purchases on the spot market with present oil prices running at 85 to 90 cents per gallon. For most of 1979 LP&L was unable to obtain fuel oil due to lack of availability. However, this did not present an operating problem due to a cool summer and mild winter (i.e., no natural gas curtailments).

1.4 Demand Projections

Table II shows the average demand for each year since 1968. The maximum peak power demand was 142.5MW during the summer of 1978. Presently, LP&L has approximately 22,400 residential, 2000 commercial and 560 municipal customers. System peak demand is projected to double by the year 2000, assuming a 3.5 percent peak power growth rate. However, this annual growth rate of 3.5 percent may be high in light of the city's expected population growth of 3.2 percent, continued direct competition with SPS, possible continuation of service area growth restrictions, and the rapidly increasing cost of electric power production (which would tend to reduce per capita consumption). Net kilowatt hours and peak demand by LP&L actually decreased from 1978 to 1979.

2.0 Fuel Use Act Implications

2.1 Applicability

None of LP&L's base and intermediate load units is excluded under Section 103(a)(7)(A) of the Act which exempts from coverage of all units with a rated capacity of less than 100 percent Btu/hr.

As indicated in Table I, LP&L has 18 units at three separate plants. Although nine of these units appear to fall below the 100 million Btu/hr threshold, three of the units are in aggregation with units totaling more than 250 million Btu/hr and thus are not excluded from the prohibitions of the FUA. The other size units are all more than 35 years old and are retired for all practical purposes.

All of IP&L's units are "existing" as defined in the FUA. However, Holly Plant Unit No. 2, a 54MW gas-fired unit came on-line in June 1978. Concerned that it might be defined as a "new" facility, LP&L applied to ERA and Holly No. 2 was granted designation as an existing unit. Except for this application, LP&L has not had any other contact with ERA regarding the FUA. LP&L perceived it might have a problem as a result of an APPA article contacted ERA/OFC regarding the status of Holly No. 2.

None of LP&L's units are coal capable and are not candidates for conversion orders FUA Section 301(b).

2.2 Compliance Strategies

LP&L must convert from its total reliance on natural gas to alternate fuels by 1990 in order to meet the objectives of the FUA. Following are several possible scenarios in which LP&L could meet its legal obligations under the FUA. It is likely that several of these options could be pursued simultaneously.

2.2.1 Existing Units

Fuel Conversion: Another option available to LP&L is to base load Holly Station No. 2 continuous oil firing and making modifications to its other units such that by 1990, LP&L could meet its FUA obligations by simply switching to oil. The advantages offered by this approach are that LP&L could avoid large capital outlays which would be required to build new coal-fired capacity. This scenario could avoid the premature retirement of LP&Ls newer units and could prove to be least burdensome if

Congress were to repeal the gas use prohibitions on existing utilities --especially if natural gas prices remain stable or escalate slowly.

A disadvantage of converting to oil is primarily economic. If the Btu-equivalent cost of oil continues to be significantly higher than gas, LP&L would incur sharply higher generating costs in 1990. A second disadvantage would arise if Congress were to amend the FUA to require reductions in total oil/gas usage, thus preventing this method of compliance.

System Compliance Option: Designed especially for utility systems which are heavily dependent on natural gas Title V of the FUA provides for the continued use of gas to year 2000 for qualifying utilities. Utilities which desired to exercise this provision, the System Compliance Option, had until January 1, 1980, to qualify. LP&L officials said they were not aware of this provision until after January 1, 1980. Even if they had been aware of the system compliance option (SCO), it is not clear whether LP&L would have mounted the effort to comply in this manner. The stipulations under the SCO would sharply limit LP&L's future operating flexibility and would still require substantial conversion in order to reduce gas usage to 20 percent of its base period (1976-87).

Permanent and/or Temporary Exemptions: LP&L could pursue a variety of temporary and permanent exemptions to extend its planning horizons, to provide increased operating flexibility, and to ensure that its latest generating units are allowed to serve out their useful lives. (Holly Unit No. 2 will have served out its 35 year "life" in year 2013).

From among 21 possible temporary and permanent exemptions, the following appear to be relevant to LP&L's circumstances:

Economic: Permanent and temporary exemptions based on a finding that the cost of using any alternate fuel substantially exceeds the cost of using gas.

Temporary exemption for units which will be retired within five year period.

Peak Load: Temporary or permanent exemption to operate a gas-fired unit for peak load purposes only.

Cogeneration: LP&L could join with a new or existing industry or institution to build a new cogeneration facility fired by natural gas, if several criteria were met.

Fuel Mixtures: Existing powerplants using synthetic fuels from municipal or agricultural wastes are given special encouragement through the fuel mixtures permanent exemption which would permit a carefully determined volume of natural gas to be used in such dual-fueled facilities.

Emergency purposes: LP&L could maintain one or more units on standby to be used for reliability purposes only (in forced outages).

Use of gas in units with less than 250 million Btu/hr heat input: LP&L could obtain an exemption for several units which individually have a heat input rate of less than 250 million Btu/hr, if these units were being used as base load units in April 1977.

Although it does not appear that environmental or site limitations will constrain the construction of new coal-fired capacity in this area, there are a variety of exemption possibilities under Section 212 of the FUA. Most of these are similar to those identified above. However, one deserves special attention because of its possible applicability to other publicly-owned utilities. The inability to obtain adequate capital for new coal (or other alternate fuel) fired unit is grounds for a permanent exemption. Thus, if the voters of Lubbock fail to approve bonding authority for a new coal-fired plant but would approve a gas-fired unit at less than half the cost, this could constitute an inability to obtain capital and entitle the utility to an exemption to burn gas.

2.2.2 New Capacity

Alternate Fuels: LP&L could comply with the FUA by constructing a large new alternate fuel-fired facility. No such plans are now underway, although LP&L has contracted with Battelle to investigate the feasibility of using municipal solid waste as a supplemental fuel. In addition, there have been discussions between LP&L and Lea County Electric Coop in New Mexico about a joint-action coal plant.

If LP&L were to decide to build a large new generating plant, it could build a facility large enough to accommodate future growth and replace its existing gas-fired base load demand--thus meeting its FUA obligations. Presumably this option would demonstrate the "good faith efforts" referred to in the FUA as a condition for the granting of exemptions. (LP&L would probably still need to use some of its existing units for intermediate or peak load and thus require exemptions.)

However, the decision to pursue this option would be difficult in many respects. First, the voters would have to grant bonding authority; a prospect which LP&L officials believe to be slim. (The last gas-fired unit required three elections before voters approved funding.) Secondly, given the uncertainties associated with LP&L's future growth, LP&L may not need additional generating capacity for several decades (assuming no service area expansion and little per capita increase in demand). It is unlikely that a new coal-fired unit could be economically justified under a no-growth or sharply curtailed growth situation, given the existing investment in gas-fired capacity. Finally, a decision to build a large new facility would require a substantial commitment to the long-term survival of LP&L, a commitment which would be difficult to ensure in view of the unique relationship among LP&L, SPS, and their customers.

3.0 Purchased Power

Perhaps the most likely and least burdensome method for LP&L to comply with the FUA is to use its contract with SPS to purchase up to 100MW of base load power. Although the contract envisions even larger electricity exchanges (with a four-year notice), 100MW should meet LP&L's base load power requirements for several years. This would shift the burden of converting to alternate fuels to SPS (which has several existing and planned coal units) since the FUA, Sec. 103(a)(6), includes electricity within the definition of "alternate fuels."

The intertie between LP&L and SPS could fundamentally alter the competitive relationship between the two utilities. To the extent that LP&L relies on the contract to furnish base load, this relationship will come to resemble that of a wholesale power supplier and a local distributor.

4.0 Alternative Technology Options

Of the viable, alternative technology options available to LP&L, the following technologies are currently being pursued.

direct firing of oil (all gas-fired boilers are designed or have been retrofitted to burn some oil)

purchase base load power form another utility (1982 agreement with SPS for 10 to 100 MW)

direct combustion of coal (very preliminary discussion with nearby utilities for a joint ownership plant)

direct combustion of municipal solid waste (under study by Battelle)

conversion of existing gas-fired boilers and turbines to combine cycle operation (under study by Tippett and Gee)

Of these options, only the direct firing of oil and the purchasing of power from another utility are definitely available in the 1980's. Another viable option would be the use of cogeneration at the Holly Station Plant. Land is available around this plant for the construction of industrial-commercial facilities capable of utilizing low-pressure steam.

Table III summarizes the applicability of the above mentioned technical options available to LP&L as well as the other options addressed in Task 5. Technological acceptance ranks the commercial status and degree of commercial use in the U.S. Environmental acceptability ranks the degree of environmental control and hazard. Cost acceptability ranks the economic capability of LP&L to implement the technology. The overall acceptability combines the three previous categories, weighting their value in light of LP&L's particular situation. As can be seen, LP&L, in varying degrees, is pursuing those options which are most applicable to their system.

5.0 Conclusions

Although LP&L offers a unique instance of head-to-head competition within a particular service area, its FUA-related problems are not unique.

Because of the vastly increased prices of oil and natural gas, small utilities now dependent on these fuels will find it difficult to compete with the larger utilities which have the technical sophistication and capital to convert to alternate fuels. The FUA reinforces this economic stimulus.

The Lubbock experience suggests that there is value in preserving a small system (at least to the Lubbock rate payers who enjoy lower rates and better service). At issue is whether the national interest is best served by these small systems and, if so, should some accommodation be made in the FUA to recognize the difficulties faced by individual small utilities in complying with the Act. LP&L management suggests that very small utilities (500 MW) be exempted from the Act and that existing units be allowed to serve out their useful lives rather than meet a 1990 deadline. Although either of these changes would provide considerable relief to LP&L, both would result in increased gas use.

A less drastic change in the Act might be to allow small utilities to continue to fire gas in existing units for base load generation for what is generally accepted as a normal unit lifetime. Perhaps such a revision could be combined with the amendments to the FUA affecting oil use in existing units.

TABLE III
SUMMARY OF LP&L'S TECHNOLOGICAL ALTERNATIVES

ALTERNATIVE TECHNOLOGY	TECHNICAL ACCEPTABILITY	ENVIRONMENT ACCEPTABILITY	COST ACCEPTABILITY	OVERALL APPLICABILITY TO LP&L	COMMENTS
Direct combustion of					
Coal	VA*	A**	NA***	A	Too costly to do alone--is looking at joint ownership situations--funding would be very difficult.
Wood	--	--	--	NA	No forests in area.
Municipal Solid Waste	A	A	A	A	Presently studying this possibility. Federal funding may be possible.
Coal/Oil Mixture	--	--	--	NA	All gas units are not suitable for retrofit.
Retrofitting of Existing Plants (combined cycle)	A	VA	A	VA	Presently studying retrofit of two boilers and two gas turbines to combined cycle operation.
Low-Btu Gasification	NA	A	NA	NA	Cost would probably be prohibitive.
Cogeneration	A	VA	A	A	Area available around Holly Station for new industry to locate.
Heavy Fuel in Engines and Turbines	--	--	--	NA	Diesel engines used only for standby, gas turbine retrofit not commercial.
CAS	NA	?	NA	?	Do not know if subsurface formation exist--cost would probably be prohibitive.
Low-Head Hydro	--	--	--	NA	Few acceptable hydro locations.
Fluidized Bed Combustion	NA	A	NA	NA	Cost would be prohibitive as well as not commercially proven.
Medium-Btu Gasification	NA	A	NA	NA	Cost would be prohibitive. If gas were available, purchase agreement could be made.
Solar	NA	VA	NA	NA	Cost would be prohibitive.
Purchase Power	VA	VA	VA	VA	Purchase agreement for power from SPS in place for 10-100MW in 1982.

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*VA - very acceptable or applicable **A - acceptable or applicable ***NA - not acceptable nor applicable

The LP&L also raised the issue of how the FUA constraints combined cycle generation by reconfiguration of existing equipment. Perhaps such cases could be delt with under the public interest exemption on a case specific basis.

From a technological, environmental, and economic standpoint, LP&L's options for complying with the FUA are costly and limited as summarized in Table III. The easiest compliance option and the option which requires the least amount of capital expenditure on LP&L's part is to purchase power from SPS. However, in the long run, this option reduces the independence of a small utility system and tends to convert it to an extension of a large utility system.

CASE STUDY NO. 9
WESTERN FARMERS ELECTRIC COOPERATIVE 1/
ERA REGION 22

1.0 System Description

1.1 Service Area and Customers

Western Farmers Electric Cooperative which is headquartered in Anadarko, Oklahoma, serves an area of 50,000 square miles covering western and southeastern Oklahoma and small portions of Kansas and Texas. Western Farmers has 9 member distribution responsible for supplying electrical power and energy resources through its own generation sources or purchased or wheeled power from neighboring utilities. The Coop has also negotiated interchange contracts with six municipal systems located in Oklahoma (4) and Texas (2).

Western Farmers is a generation and transmission cooperative providing wholesale power to its members. In 1978 the net generation from Western Farmers' system totaled 2.6 billion KWH.

Table 1 lists the members and provides data on number of customers each member serves for year 1978.

Table I Customers

Member	Customer
Alfalfa Electric	5,369
Caddo Electric	11,699
Canadian Valley Electric	12,582
Chartan Electric	11,543
Ammarian Electric	8,739
Cotton Electric	14,245
East Central Oklahoma Electric	15,266
Harmon Electric	2,689
Kay Electric	4,757
Kiamichi Electric	9,616
Kiwash Electric	4,921
Northfolk Electric	4,505
Northwestern Electric	7,973
Oklahoma Electric	16,331
People's Electric	10,408
Red River Valley Rural Electric	7,786
Rural Electric	6,152
Southeastern Electric	7,387
Southwest Rural Electric	6,790

1.2 Existing Generating Facilities

Western Farmers generating facilities consist of all gas fired units. Of the 718MW net generating capacity, 6 units (about 391MW), 3 gas-fired steam turbine units and 3 gas- or oil-fired combined cycle units are located in Andarko and three gas-fired units (about 323MW in Mooreland.)

1/ Report on the Analysis of the Powerplant and Industrial Fuel Use Act of 1978. For the Western Farmers Power Cooperative. Preliminary Report. Burns & McDonnel, Kansas City. April 22, 1980.

An agreement exists between the Coop and Southwestern Power Administration for 260MW of peaking power as well as supplemental peaking and excess energy. The agreement is in effect until May 31, 1999.

Western Farmers also purchases power from the Public Service Company of Oklahoma (PSO) which is wheeled directly to members of the Coop that are connected to the PSO's transmission system.

In 1978, Western Farmers net system load including wheeled power was 2,970, 350, 000 kwh consumed by approximately 169,000 customers. Fuel consumed by the Coop's facilities in the same year totaled 24,644,670 mcf of natural gas and 248 barrels of oil.

1.3 Fuel Sources

The Coop obtains its natural gas from 134 wells of which 70 are connected to producer's lines and 64 to Western Farmers. Western Farmers received a maximum daily delivery of 91,000,000 cubic feet which is estimated to meet projected requirements. Plans are to replace base load gas-fired generation with coal-fired and nuclear generation.

1.4 Demand Projections

The demand for the remaining part of the century is estimated to increase annually by 5.98% from 1980 to 1994; and 5.14% from 1990 to 1995; and 4.32 percent from 1995 to 1999. Table II summarizes the utility's data and demand estimates.

Table II. Projected Demand

Year	Energy	Peakload
1980	3,390 GWh	650 MW
1985	4,573	898
1990	5,737	1152
1995	7,174	1468
2000	8,829	1807

2.0 Fuel Use Act Implications

2.1 Applicability

Prior to the enactment of FUA the Western Farmers Electric Cooperative had already embarked on a plan to move away from relying solely on natural gas to generate power.

Since Western Farmers' units have been classified as existing units within the context of the Fuel Use Act and did use natural gas in 1977, Western Farmers can continue to use natural gas in these units without an exemption being required before 1990 but with one constraint. Western Farmers cannot use natural gas before 1990 in greater proportions either during calendar years 1974 through 1976 or during the first two years of initial operation if the unit began operation on or after January 1, 1974. This constraint can be waived if an exemption is filed and/or granted for the current time up to January 1, 1990. Thus, while FUA Title III prohibitions do not greatly affect Western Farmers' study operation before 1990. Title III prohibitions will cause a complete restriction of natural gas use on or after January 1, 1990 unless exemptions are obtained. Title III exemptions, both temporary and permanent are open to petition under Subtitle B.

2.2 Compliance Strategies

2.2.1 Existing Units

Fuel Conversion: Western Farmers requested that General Electric investigate the possibility of burning gasified coal in their combined cycle units. The results of the inquiry indicated that for conversion to low Btu gas extensive modification would have to be carried out costing approximately $1.5 million per unit. It was also pointed out that this technology had only been demonstrated on a laboratory scale. On the other hand, medium Btu gas which is technically feasible could be used with little or no modifications. As a follow-up the company attempted to obtain cost figures. Data was found to be scant on this subject. The most useful data indicated that investment in that type of facility would cost $72.5 million (in January 1980 dollars) with an annual percentage cost (less fuel) of $1.9 million (in mid-1980 dollars).

Western Farmers does not appear to be serious or anxious to pursue fuel conversion options. Most probably because they already are developing a plan for their future system which did not include conversions perceiving them as technically infeasible and costly. The Coop has not, however, done or commissioned any indepth studies on fuel aternatives.

Temporary/Permanent Exemptions: Western Farmers is severely impacted by the prohibitions curtailing the use of natural gas in existing units on January 1, 1990.

In order to comply with the Act as well as meet future estimated demand, consultants, Burns and McDonnell, have investigated exemptions permitted under the Act. The most effective exemptions appear to be permanent exemptions for intermediate and peak load units. Under current system plans, the baseload units are expected to phase into intermediate units. The suggested strategy is to apply for an intermediate load exemption first. If it is unsuccessful, then the Company would file for a peakload exemption. A decision has not yet been reached on the strategy to pursue.

System Compliance Option: Application of the System Compliance Option would be highly restrictive to the present capacity resources of Western Farmers after 1990. However, prior to 1990, the System Compliance Option offers a possibly unrestricted use of natural gas in existing units. Prior to 1990, projected natural gas use levels are subject to some negotiations with the Economic Regulatory Administration. In general, an acceptable plan would utilize natural gas in existing units at a level not go exceed the 1976 base period use except in emergency or extreme short-term situations. There is no definitive guideline for the use of natural gas. The consultants report noted a system compliance option is of value to the utility only if the plan would liberally and adequately provide for the use of natural gas which would meet system demands. The report recommended a meeting be held with ERA to determine the probable allowable levels of natural gas consumption ERA would permit under a System Compliance Plan.

2.2.2 New Capacity

Prior to the FUA, Western Farmers had already began developing additional capacity to meet the growing energy requirements of the area. Two types of bulk power supply sources are being pursued -- construction of a new plant and joint ownership of a new plant.

The Coop now has under construction a 376 MW coal-fired generating plant which is scheduled to begin operations in 1982.

The Company has pointed out that FUA, requiring specific actions at specific times, makes it incumbent on it to try to accomplish additions of generating equipment to the system in keeping with a series of legislative and governmental regulations over which it has absolutely no control. The environmental considerations, although worthy of accomplishment, are extremely expensive and are very time-consuming when it comes to obtaining permits to build generating plants. The decision to build the Black Fox Nuclear Plant was made in 1973. Seven years have passed and a construction permit has not been issued, and in view of Three Mile Island, it is anybody's guess as to when it will be issued. With a completion data extended to 1987, over 14 years will have elapsed since the project was originated. Obviously, this forecloses any future consideration of other nuclear plants to replace gas. The coal-fired plant, which is now under construction, commenced in 1976 and is scheduled to go on the line in 1982. A coal-fired plant starting today would probably take 8 to 10 years from origination to completion in view of all the regulations that must be satisfied. With Black Fox being in a state of suspension, substitute generation cannot be planned for financing and other reasons. FUA, according to the company does not take these itemss into consideration except under the veiled possibility of obtaining emergency gas.

3.0 Joint Ownership

Westerm Farmers has also agreed to participate in the Black Fox units 1 and 2 with the Public Service Company of Oklahoma and Associated Electric Cooperative. Western has negotiated for a 200MW share in each unit. The decision to build the plant was made in 1973 but the owners are still awaiting a construction permit. As a result the completion date has moved from 1985 and 1987 for unit 1 and 2, respectively, to 1987 and 1990.

Conclusions

Western Farmers is in somewhat of a dilemma concerning the Fuel Use Act. Prior to its passage, the Coop had already embarked upon a plan under which it was reducing its reliance on natural gas by building a coal plant and participating in nuclear units. However, due to delays in obtaining a construction permit for the nuclear units, the Company is facing a problem with the FUA.

In the interim period i.e., up to 1990, Western Farmers problem is not so crucial in that it is permitted to burn the same portion of natural gas it burned in 1977 and in 1982 the coal fired unit will be in operation.

The potentially critical period for the Coop is 1990 and after, when the Company is prohibited from burning any natural gas. The system plans as initially developed with the nuclear and coal units on line in the late 1980's would result in 82% of the electricity consumption being met with these new units, the remaining needs supplied by purchased power, and the current generating units used for intermediate and peaking loads. If the nuclear units do not come on line as scheduled and the burning of natural gas is prohibited, Western will have difficulty in meeting even the minimum needs of its members.

Although Western Farmers has a number of options available to it to comply with FUA the most economical and efficient, according to their analysis, is to continue to burn natural gas. The Coop is now considering the possibility of complying with FUA by filing for permanent exemptions for its current units classifying them as intermediate and peaking units. The System Compliance Plan is another option under consideration, but before filing Western is anxious to determine if the allowables under the plan will be sufficient.

CASE STUDY NO. 10 1/
WEST TEXAS UTILITIES COMPANY
ERA REGION 23

System Description

1.1 Service Area and Customers

West Texas Utilities Company (West Texas) is an investor-owned electric utility serving 53 Texas counties over an area of 53,000 square miles. Service to farms and ranches covers a good portion of their service area as well as the cities of Abilene, San Angelo, Vernon and Childress. The company's headquarters is in Abilene. It is an operating subsidiary of the Central and South West Corporation.

West Texas' wholesale customers include 18 rural cooperatives which account for 13 percent of their 1979 peak load. The company's service area extends from the Oklahoma border south across the central part of the state to the Mexican border, and encompasses approximately 20 percent of the total land area of Texas. Table I provides information on power consumption by customer class for West Texas Utilities.

Table I. Customers and Consumption (1979) 2/

Class	No. of Customers	Energy (Kwh/year)
Residential	120,762	985,026,000
Commercial	20,455	746,493,000
Industrial	5,240	1,098,979,000
Other	3,557	1,753,003,000
Total	150,014	4,583,501,000

1.2 Existing Facilities

West Texas owns and operates 18 natural gas-fired generating units located at eight plants for a total net system capacity of 1,051MW. All the units are of relatively small size and are utilized in a mixture for peaking and base load capacity. All units are designed for natural gas fuel with only one unit having continuous oil-fired capability. Three-fourths of the units have 20 years or more service life remaining; the most recent

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werplant and Industrial Fuel Use Act of 1978, Comments of West Texas ilities Company, Abilene, Texas. June 6, 1980.

79 Annual Report, West Texas Utilities Company, Abilene, Texas. March 1980.

units placed in service in 1974 and 1977. Several of the units can burn for short periods of time. In addition, the company operates several small unattended diesel and internal combustion engines.

Given the large geographical service area covered by West Texas (Figure 1), the generating units are widely dispersed over 53,000 square miles. The system is interconnected with 3,750 miles of transmission lines. Table II details the West Texas generating system.

1.3 Fuel Sources

There are no supply problems with natural gas for West Texas. Lone Star Gas Company is the major supplier for seven of the company's gas-fired units. Presently, this contract is effective until December 31, 1989, with a five year extension option, and supplies the fuel for 87 percent of the company's generating capacity. Phillips Petroleum Company is the supplier for the other units under a long-term contract through 1988. West Texas gas supplies have been consistent except for some short limitations during winter months. There are some contract limitations which prevent the company from purchasing from other suppliers.

The company has found it difficult to pursue long-term contracts for supplemental gas through the 1980's. It feels that the off-gas provisions of the Fuel Use Act (FUA) are responsible for this difficulty. West Texas finds their gas procurement attempts very limited.

The utility has recently initiated efforts toward obtaining non-pipeline quality low-Btu gas. The cost for this gas is very competitive with that from major suppliers and offers opportunity for use during curtailments. Contracts for the low-Btu gas have not been successful due to certain inabilities of the supplier, however, West Texas is continuing to examine opportunities for obtaining the gas. Low-Btu gas represents a less expensive gas supply but is limited in its reserve to offer long-term supply assurances.

1.4 Demand Projections

West Texas anticipates a modest growth rate through 1990, increasing slightly to 2000. Through 1985 and 1990, the utility expects a 3.9 percent annual demand growth (peak). Their net generating capacity is projected to be 1,531MW in 1990.

The annual demand growth (peak) is projected to be 4.5 percent through 2000. West Texas net generation for the year 2000 is projected as 2,412MW.

2.0 Fuel Use Act Implications

2.1 Applicability

All West Texas steam generating units are subject to the requirements of Title III. As indicated in Table II, the utility has 18 units at eight plant sites over their service area. Two of these units may fall below the 100 million BTU/hr treshold, but the remaining are not excluded from prohibitions. None of the units are more than 25 years old and past the mid-point of their expected service years. Two units are 50 and 52 years old and will be retired before 1990. Three of the units are less than ten years old (Table II).

All of the units are "existing" under the FUA definition and none, at this time, are subject to conversion orders.

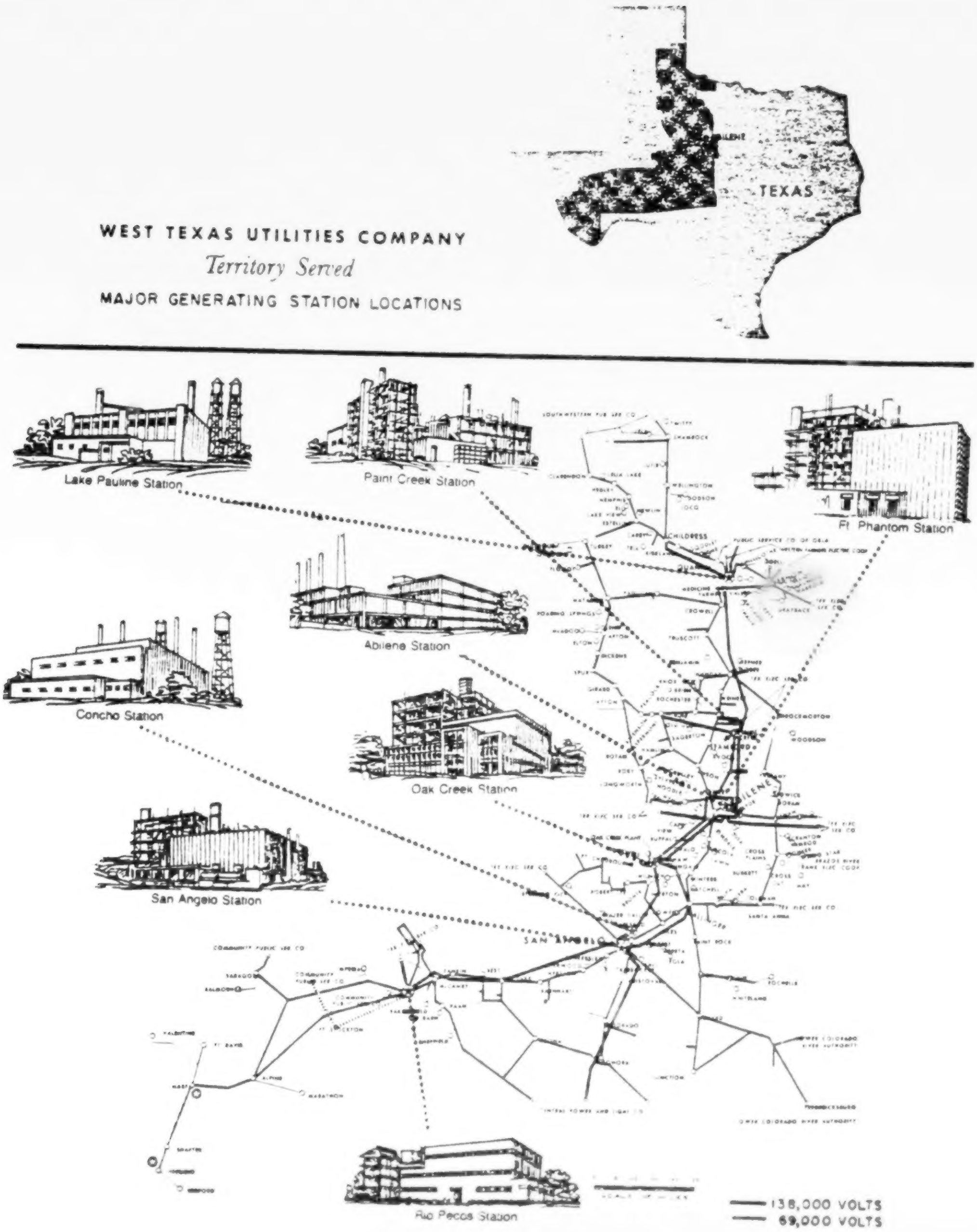
WEST TEXAS UTILITIES COMPANY
Territory Served
MAJOR GENERATING STATION LOCATIONS
TEXAS
Lake Pauline Station
Paint Creek Station
Ft Phantom Station
Abilene Station
Concho Station
Oak Creek Station
San Angelo Station
Rio Pecos Station
CHILDRESS
ABILENE
SAN ANGELO
138,000 VOLTS
69,000 VOLTS

FIGURE I

EXISTING UNITS

TABLE II

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
Abilene		3	Steam	Peak	--	8	1948	NG	--	Oil (Short term)		
		4	Steam	Peak	--	18	1949	NG	--	Oil (Short term)		
Paint Creek		1	Steam	Peak	--	34	1953	NG	--	"		
		2	Steam	Peak	--	34	1955	NG	--	"		
		3	Steam	Peak	--	53	1959	NG	--	"		
		4	Steam	Peak	--	110	1971	NG	--	"		
Lake Pauline		1	Steam	Peak	--	19	1928	NG	--	"		
		2	Steam	Peak	--	27	1951	NG	--	"		
Oak Creek		1	Steam	Peak	--	81	1962	NG	--	"		
Concho		3	Steam	Peal	--	15	1930	NG	--	"		
		4	Steam	Peak	--	35	1953	NG	--	"		
Rio Pecos		4	Turbine	Comb. Cycle	--	4	1954	NG	--	-		
		5	Steam	Comb. Cycle	--	36	1959	NG	--	Oil (Short term)		
		6	Steam	Base	--	95	1969	NG	--	"		
San Angelo		1	Turbine	Comb. Cycle	--	24	1965	NG	--	-		

EXISTING UNITS

TABLE II Cont.

STATION NAME	LOCATION	UNITS	UNIT PRIME MOVER	TYPE (BASELOAD, ETC.)	COGENERATION CAPABILITY	NET GENERATING CAPACITY (MW)	ON-LINE	PRIMARY FUEL(S)	HEAT INPUT RATE (BTU/HR.)	ALTERNATE FUELS	MAXIMUM HEAT RATE (BTU/KWH)	RETIRE-MENT DATE
San Angelo		2	Steam	Comb. Cycle	--	103	1966	NG	-	Oil (Short term)		
Fort Phantom		1	Steam	Base	--	155	1974	NG	-	-		
		2	Steam	Base	--	200	1977	NG	-	Oil		
Matador		1	Diesel	Peak	--	1	1955	Diesel	-	-		
Presidio		1	Diesel	Peak	--	1	1929	Diesel	-	-		
		2	Diesel	Peak	--	.05	1930	Diesel	-	-		
		3	Gaso-line	Peak	--	.1	1951	Diesel	-	-		
		4	Diesel	Peak	--	.9	1948	Diesel	-	-		
		5	Diesel	Peak	--	.9	1948	Diesel	-	-		
Fort Stockton		2	Turbine	Peak	--	5	1958	NG	-	-		

2.2 Compliance Strategies

West Texas must seek exemptions for all their units in order to continue operating beyond January 1, 1990, until new units come into operation (see 2.2.2). The utility could convert to oil, but the cost appears prohibitive and the company officials have expressed some concern regarding becoming dependent on a fuel that is expensive and has a questionable future, such as oil. West Texas has applied for temporary Public Interest Exemptions for 14 of their units.

The strategy of the last resort would be to retire all their units prematurely or reduce their power output to peaking only. This strategy would then necessitate attempts to purchase power from neighboring utilities who will also be subject to compliance of the FUA and, perhaps, vulnerable to the same strategy. As an investor-owned utility, the company is concerned about achieving full benefit from their total plant investments and lower costs to their stockholders and ratepayers.

2.2.1 Existing Units

Because of the location of natural gas resources in the service area, West Texas has designed their generation for this fuel. There are no production level coal or lignite reserves found in the utility's service area.

Fuel Conversion: As cited above, West Texas generating stations are limited in their ability to burn oil. Fifteen units have capability for oil but only for short-term, usually during curtailment periods. Fort Phantom Units 1 and 2 can use oil for long periods of time. However, Unit 1 requries frequent boiler maintenance when oil is burned. No other units in the system are capable of using oil.

The company has evaluated the feasibility for coal conversion for each system unit. With the older units, there are space limitations for coal handling as well as a severe lack of adequate cooling water required by coal-fired units. The engineering design of all the units (furnace volumes, air heater design, superheater design, heat transfer surface areas, etc.) prohibit conversion to coal fuel without rebuilding the entire boiler and installing environmental control equipment. Since the largest unit is 200MW, West Texas determined that it was not economical or technically sound to convert these boilers to coal.

In addition to space limitations at a number of existing sites, two other significant factors contributed to the determination regarding coal conversion. West Texas serves an area which is vulnerable to short water supplies. There are no major additional sources of water for cooling at or near the company's existing plants. The company has analyzed water requirements for coal conversion and found water requirements could not be met under a coal conversion scenario. Water requirements would range from 0.50 gallons of water per Kwh generated to 0.78 gallons depending on whether cooling towers and/or pollution abatement equipment is part of the operation. With their present gas-fired units, water use averages 0.32 gallons per Kwh.

A shortage of existing railroads presents another problem for coal conversion. In order to burn coal, it conversion appeared likely, the utility would have to build new rail spurs, or rebuild older tracks to plant sites, in order to handle coal deliveries.

Permanent and/or Temporary Exemptions: West Texas could pursue a number of exemptions for purposes of changing to alternate fuels by 2000. The following appear to be within the utility's range of operation:

- Permanent or temporary exemptions based on a finding that the total cost of an alternate fuel substantially exceeds the cost of using gas;
- Temporary exemption for units to be retired within five years;
- Emergency exemption for reliability purposes;
- Peak load exemptions for several small units in system;
- Fuel mixture exemption based on use of low-BTU gas;
- Exemption for units with less than 250 million BTU heat input; possibly applicable for several units; and
- Exemption due to site limitation or environmental requirements; specific for each unit in the system.

Because of West Texas' unique geographical situation, several of the above might also be utilized under Title II of the Act regarding new facilities.

2.2.2 New Facilities - Joint Ownership

In the mid-1970's, West Texas began to investigate a move toward future reliance on coal, nuclear or lignite generation. The utility has expressed concern over capital requirements necessary for building new coal-fired generating stations. To relieve the financial impact, West Texas has begun their switch to alternate fuels by purchasing a share (307MW) of the proposed Oklaunion Powerplant (640MW) which is scheduled for operation in 1987. In the future, as with the Oklaunion plant, capacity expansion will be planned by the Central and South West System, of which West Texas is a member. 3/ West Texas anticipates participating in 20 other coal or nuclear units between 1987-2000.

In addition to planning for coal or lignite units, West Texas has been participating in studies for other alternate fuels or technologies. These studies include a geothermal project in the western part of Texas, a demonstration coal gasification plant at San Benito, Texas, and development of a cogeneration plan with the Texas Public Utility Commission and the Federal Energy Regulatory Commission. West Texas, with two consulting firms, plans to submit a project to the Department of Energy for a feasibility study to repower 60MW of the Paint Creek Unit 4 with solar energy.

3/ Other members are Central Power and Light Company, Public Service Company of Oklahoma and Southwestern Electric Power Company.

West Texas purchases some power throughout the year when it is economical to do so. In 1979, during the peak hour, West Texas received 29MW from three neighboring utilities. The Lower Colorado River Authority provided 11MW of firm power and 18MW of unscheduled power was received from Central Power and Light Company and Public Service Company of Oklahoma (also operating subsidiaries of the Central and South West system). Normally, unless economy purchases can be made, net transfer or power through interconnects with these companies is maintained near zero. For the year 1979, West Texas received a total of 276,876 MWH and delivered a total of 452,686 MWH. These purchases and sales, normally made for economic reasons, were with affiliates and other interconnected companies.

4.0 Conclusion

West Texas Utilities has some immediate compliance problems. The fact that the utility has been in the process of moving off-gas since 1975 has not alleviated the regulatory requirement restricting the use of natural gas as specified in the FUA.

The company emphasizes that it can decrease its gas use by a considerable amount as new alternate fuel plans are placed in service. By the year 2000, it expects to reduce its dependence on natural gas to when only 24 percent of its fuel requirements will come from this source.

Forcing the utility to completely convert to coal in the near term will create financial difficulties that the company may not be able to meet successfully. Similarly, a rapid conversion schedule would present almost insurmontable environmental difficulties which would counter any progress toward moving off-gas. Most noticeable here are the lack of available water in the companies' service area and problems with meeting air quality standards.

Presently, West Texas feels that the prohibitions of Title III are overly restrictive with regard to their generating system. The utility's planning has been based on the use of their existing facilities for the economic life of each unt. The FUA does not take into account that West Texas began, as early as 1975, to move to alternate fuels in long term.

APPENDIX B
UTILITIES AND REPRESENTATIVES CONTACTED FOR AND/OR RESPONDING TO STUDY OF COMPLIANCE PROBLEMS OF SMALL ELECTRIC UTILITIES WITH FUA

Utilities

Atlantic City Electric
Arizona Electric Power Cooperative*
Austin, Minnesota*
Austin, Texas
Black Hills Power and Light Company*
Burbank, California*
Burlington, Vermont*
Bryan, Texas*
Cajun Electric Power Cooperative
Central and South West Services, Inc.*
Central Hudson Gas and Electric Corporation*
Central Telephone and Utilities*
Clarksdale, Mississippi*
Colorado Springs, Colorado*
Columbia, Missouri*
Columbus, Ohio*
Dairyland Electric Power Cooperative*
Denton, Texas*
Detroit, Michigan*
Dover, Delaware*
Easton, Maryland
Empire District Electric Company*
EUA Service Corporation*
Farmington, New Mexico*
Fitchburg Gas and Electric Light Company
Florida Municipal Power Agency*
Fort Pierce Utilities Authority*
Fulton, Missouri*
Gainesville, Florida*
Glendale, California*
Grand Haven, Michigan*
Grand Island, Nebraska*
Greenwood, Mississippi
Hastings, Nebraska*
Hibbing, Minnesota
Highland, Illinois*
Homestead, Florida
Houma, Louisiana*
Imperial Irrigation District*
Interstate Power Company*
Iowa Power
Iowa-Illinois Gas and Electric Company*
Kansas City Power and Light Company
Key West, Florida
Lafayette, Louisiana*
Lakeland, Florida*
Lamar, Colorado*
Lea County Electric Cooperative Inc.*
Lebanon, Ohio*
Lincoln, Nebraska*
Lubbock, Texas*
Madison Gas and Electric Company*

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* As cited in study.

Utilities

Maine Public Service Company
Marquette, Michigan*
Marshfield, Wisconsin*
Massachusetts Municipal Wholesale Electric Company
McPherson, Kansas*
Medina Electric Cooperative, Inc.*
Minnesota Power and Light Company*
Missouri Utilities Company*
Montana-Dakota Utilities Company*
Montana Power Company*
Morgan City, Louisiana*
Muscatine, Iowa*
New England Gas and Electric Association*
New Mexico Electric Service Company*
New Smyrna Beach Utilities Commission*
North Carolina Electric Membership Corporation*
Oglethorpe Power Corporation
Orlando, Florida*
Orrville, Ohio
Ottawa, Kansas*
Palo Alto, California
Plains Electric G&T*
Pratt, Kansas*
Public Service of New Hampshire*
Public Service of New Mexico*
Ruston, Louisiana*
Savannah Electric Power Company*
Sebring Utilities Commission*
Sierra Pacific Power Company*
South Mississippi Electric Power Association*
South Texas Electric Cooperative Inc.*
Southern Indiana Gas and Electric Company*
Spencer, Iowa*
St. Joseph Light and Power Company*
Sunflower Electric Cooperative*
Tallahassee, Florida*
Texas Municipal Power Agency*
Trinidad, Colorado*
Tri-State G&T Association*
Tucson Electric Power Company*
United Power Association
Upper Peninsula Power Company*
Vero Beach, Florida*
Wallingford, Connecticut*
Washington Water Power Company*
West Texas Utilities Company*
Western Farmers Electric Cooperative*
Winfield, Kansas
Wolverine Electric Cooperative*
Yazoo City, Mississippi*
Zeeland, Michigan*

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* As cited in study.

Associations

American Public Power Association (APPA)*
Committee on Power for the Southwest, Inc.
National G&T Managers Association
National Rural Electric Cooperative Association (NRECA)*

Persons

James J. Berry, P.E.*
  Executive Vice President
  Smith and Gillespie Engineers, Inc.
  Jacksonville, Florida

Peter S. Hamill
  Senior Vice President
  Stone and Webster Management Consultants, Inc.
  Denver, Colorado

James M. Hubbard*
  Executive Vice President
  A. C. Kirkwood and Associates
  Kansas City, Missouri

Alan J. Roth
  Spiegel and McDiarmid
  Washington, D. C.

J. B. Sims, P.E.*
  J. Bryan Sims and Associates
  Grand Haven, Michigan*

State Agencies

Ohio Department of Energy
New Mexico Energy and Minerals Department
Texas Energy and Natural Resources Council*

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* As cited in study.

APPENDIX C

JOINT AGENCY LEGISLATION

(Source: Lehman Brothers Kuhn Loeb, Inc.,
Public Power Joint Agency Survey, 1978.)

KEY

1. Ownership and Operation of Facilities - General Powers

Joint agency is authorized to plan, acquire, construct, maintain, operate, reconstruct, repair, improve, or lease (as lessee or lessor) facilities inside or outside state for generation, transmission, or distribution of electric power and energy.

2. Purchases and Sales - General Powers

Joint agency is authorized to purchase electric power and energy from, sell it to and distribute it to any person, political subdivision, or IOU inside or outside state.

3. Issuance of Indebtedness - General Powers

Joint agency is authorized to issue revenue bonds, notes, or other obligations, and refunding bonds, notes, or other obligations, which obligations may be sold at public or private sale.

4. Security for Indebtedness - Standard Security Arragements

Joint agency is authorized to issue indebtedness payable from revenues derived from functions, services, facilities, or other available funds of agency (including contributions from members).

State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
California (Gov't Code, Art. 1, Ch. 5)	Any 2+ public agencies (federal or state agencies and political subdivisions, including those of adjoining states) may contract to create joint agency to administer agreement if authorized by respective legislative or governing bodies.	Notice of agreement must be filed w/ Cal. Sec'y of State w/in 30 days after effective date. Public agencies cannot join w/IOU's.	May exercise any power common to all contracting entities.	May exercise any power common to all contracting entities.	General powers, but must invite bids before trying to sell bonds at private sale.
Colorado (Colo. Rev'd Stat. §§ 29-1-201—29-1-204)	Any 2+ Colo. cities and towns and/or cities and towns of adjoining state not more than 15 miles from common border may contract to form power authority.	Cities or towns cannot join with IOU's other pol. subdivisions or coop's, or w/ cities or towns of other states.	General powers/ excluding distribution/ plus power to acquire interest in or capacity share of any elec. facility.	General powers/ excluding distribution/plus power to sell to and contract with non-member cities and towns w/in 15 miles of Colo. border.	General powers.
Connecticut (Conn. Gen. Stat. §§ 7-233a--7-233w)	Any 2+ municipal electric utilities may create municipal electric cooperative (MEC) by filing concurrent resolutions of governing bodies of utilities with Sec'y of State.	MEC's must have been in continuous operation for 5+ years. Resolutions must be adopted within single calendar yr. Each municipality represented must consent to creation of cooperative. Municipalities cannot join with IOU's, coop's or some other pol. subdivisions.	General powers/ excluding distribution/ plus power to acquire interest in or capacity share of an elec. facility.	General powers/ excluding distribution. May enter into or become participant in New England Power Pool.	General powers/ plus power to issue bond anticipation notes.
Delaware (Del. Code, Tit. 22, Ch. 13)	Any 2+ Del. cities or towns may contract to form municipal electric company (MEC).	Cities or towns cannot join with IOU's, coop's or some other pol. subdivisions.	General powers/ plus acquisition of fuel deposits and operation of facilities to extract, store and transport fuel.	General powers.	General powers/ plus power to issue interim certificates.

JOINT AGENCY LEGISLATION

Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	Bond issuance approved by ordinances of governing bodies of members. Separate authorization required for each issue of securities, except securities for transmission facilities. Maximum interest rate at 8%; 40-year maximum term on obligations, maximum discount of 6% of par value.	No state regulation of rates or securities issuance, but jt. agency must conduct public hearing before revising rates.	Power of eminent domain, but cannot condemn property owned, leased or controlled by public utility.	Property w/in Cal. exempt from ad valorem taxation.	Indebtedness, interest and income therefrom exempt from taxation, except gift, inheritance and estate taxation.
Standard security arrangements/plus obligations may be secured by mortgage or other security interest in properties of power authority.	40-year maximum term on obligations.	No rate regulation of sales by power authority to contracting municipality for resale w/in corp. limits, but may have juris. over sales by such municipality outside corp. limits and over sales by authority of surplus power to other utilities.	Power of eminent domain, but cannot condemn any property owned by public utility and devoted to such public use.	Colo. A.G. has ruled that authority is municipal corp. and its property is, therefore, tax-exempt.	Indebtedness, interest and income therefrom exempt from taxation, except gift, inheritance and estate taxation.
Standard security arrangements/plus obligations may be secured by conveyance or mortgage of any property of joint agency.	Bond anticipation notes must be retired within 5 years from date of issuance; 40-year maximum term on all other obligations.	No state regulation of rates or securities issuance except to extent MEC's are subject to PUC as of date municipal coop is created.	Power of eminent domain, exercised by unanimous vote of board, but cannot condemn any property owned by any other public or private utility.	Property, income and operation exempt. In connection w/acquisition, construction or ownership of any facility outside member boundaries, coop's may make payments in lieu of taxes to appropriate taxing entity.	Indebtedness, interest and income therefrom exempt.
Standard security arrangements/plus obligation may be secured by mortgage or security interest in any property, commodity, service or interest therein.	None.	No state regulation of rates or securities issuance.	Power of eminent domain.	Property, income and operations exempt.	Indebtedness, interest and income therefrom exempt.

(Continued)

State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuances of Indebtedness
Florida (Fla. Stat. §163.01 and Fla. Stat., Ch. 361, Part II)	Any 2+ Fla. pol. subdivisions may contract to create separate legal entity.	Members of jt. agency must have owned, operated and maintained electric facilities or systems on June 25, 1975. Agreement must be approved by Fla. Dept. of Legal Affairs. Members cannot be IOU's.	General powers/ excluding distribution/ plus acquisition of fuel sources and operation of facilities to extract, store and transport fuel.	No prov. relating to power sales contracts.	General powers/ plus power to issue bond anticipation notes after bond issuance has been authorized.
Georgia (Ga. Code, Ch. 348-4)	Municipal Electric Authority of Ga. (MEAG) consists of 9 members elected by representatives of pol. subdivisions of Ga. which contracted with MEAG for purchase of elec. power.	Members of jt. agency must have owned and operated distribution systems on March 18, 1975. Members cannot be IOU's.	General powers/ excluding distribution/ plus power to aquire interest in or capacity share of any elec. facility.	General powers/ excluding distribution.	General powers/ plus power to issue bond anticipation notes after bond issuance has been authorized.
Indiana (House Enrolled Act. No. 1758)	Any 2+ Ind. cities or towns may contract to form joint agency.	Jt. agency members must have owned and operated systems on July 1, 1977. Cities or towns cannot joint w/ IOU's, coop's or some other pol. subdivisions.	May study, plan and finance systems and facilities in Indiana owned in whole or in part by its members, but jt. agency not expressly authorized to operate or lease facilities for the supply of power.	No prov. relating to power purchases and sales.	General powers.

(Continued)

Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	Jt. agency must hold election to authorize issuance of bonds or notes. Agency may litigate validation suit to determine authority to issue obligations. Interest rate on obligations may not exceed 7½% per annum, and no sale may be made at price so low that interest payments on money received exceed 7½% per annum. Bond anticipation notes must be repaid w/in 3 yrs. from date of bond authorization.	No state regulation of rates or securities issuance, but is subject to regulation of construction or operation of GT facilities.	Power of eminent domain.	Property, income and operations exempt.	Indebtedness, interest and income therefrom are exempt.
Standard security arrangements.	MEAG may not issue bonds until it has power sales contracts with at least 5 pol. subdivisions and until after judgment in a validation suit filed by the district attorney in the Superior Court of Fulton County; 50-year maximum term on obligations.	No state regulation of rates or securities issuance.	Power of eminent domain.	Property and income exempt.	Indebtedness, interest and income therefrom exempt.
Standard security arrangements.	None.	Indiana Public Service Commission must approve project, members' participation and issuance of obligations before obligations may be issued by agency.	No prov.	No exemption from taxation.	Indebtedness, interest and income therefrom exempt from taxation, except gift and inheritance taxation.

(Continued)

State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
Kansas (1977 Kan. Session Laws, Ch. 48)	Any 2+ Kan. cities may contract to create municipal energy agency (MEA), which agreement must be authorized by resolutions of governing bodies of cities.	Members must have operated systems in 1976. Agreement and amendments must be approved by A.G. Authorizing resolution, which must be approved by each city, is effective 60 days after publication unless protest petition of 10% of registered voters filed within 60-day period. If petition filed, special election must be called approving resolution. Cities or towns cannot join with IOU's, coop's or some other pol. subdivisions.	General powers/ excluding distribution/ excluding power to construct, acquire or operate coal gasification facility or pipeline for transportation of coal slurry unless authorized by law/plus power to acquire interest in or capacity share of any elec. facility.	General powers/ excluding distribution.	**General powers/ plus power to issue bond anticipation notes after bond issuance has been authorized.**
Louisiana (La. Rev'd Stat., Tit. 33, Ch. 10-A)	Any La. municipality by resolution of governing body may join La. Energy and Power Authority (LEPA).	Members must have operated systems on July 20, 1979. Municipality must hold special election re joining LEPA before resolution effective. IOU's coop's and pol. subdivisions cannot be members.	General powers with respect to facilities located w/in La. excluding power to construct transmission facilities unless LEPA cannot provide therefor by contract with IOU's with existing facilities under fair and reasonable terms or unless ordered to do so by regulating authority.	General powers/ excluding power to sell or provide for transmission of power at retail. Before municipality can contract with LEPA, must hold public hearing and issue public notice of intention to contract 4 times prior to hearing. If 5% of the registered voters contest contract, special election must be called to approve contract.	**Power to issue only revenue bonds.**

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements/plus obligations may be secured by mortgage or pledge and grant of security interest in properties of jt. agency.	**Maximum interest rate at 9%; 40-year maximum term on obligations; bonds not sold at price less than par value.**	Kan. Corporation Commission has juris. over rates and securities issuance. Also subject to regulation of construction or operation of GT facilities.	Power of eminent domain, subject to approval of Kan. Corporation Commission, but cannot condemn facilities of other utilities.	Property exempt, but must pay to each appropriate taxing authority the amounts which would be assessable were such property owned by public utility.	Indebtedness, interest and income therefrom exempt from taxation, except inheritance taxation.
Standard security arrangements.	No obligations may be issued until after power sales contract between municipality and LEPA has been executed. (See Purchases and Sales of Power). Maximum interest rate at 8%.	No state regulation over rates, but La. State Bond Commission has juris. over issuance of indebtedness. Also subject to regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of other utilities, state or federal departments or pol. subdivisions.	Property exempt from property taxes, but may pay to each appropriate taxing authority an amount in lieu of taxes.	Indebtedness, interest and income therefrom exempt from taxation, except inheritance and estate taxation.

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State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
Massachusetts (Act of 1975, Ch. 775)	Any Mass. city or town may become member of Mass. Municipal Wholesale Electric Company (MMWEC) by vote of majority of members of each branch of city government or of voters present and voting at town meeting.	Membership requires vote of all branches of city government or of electorate. IOU's, coop's and some pol. subdivisions cannot be members.	General powers/ excluding distribution/ plus power to acquire interest in or capacity share of any elec. facility.	General powers/ excluding distribution.	General powers.
Michigan (Mich. Stat. §22,189)	Any 2+ Mich. pol. subdivisions may create jt. agency by adoption of resolutions and articles of incorporation by governing bodies.	Members must have operated systems on Jan. 1, 1977. IOU's, coop's and some other pol. subdivisions cannot be members.	General powers/ excluding distribution/ plus power to acquire interest in or capacity share of any elec. facility.	May purchase, sell or exchange energy for resale only. May sell to city, county, incorporated village, township or metropolitan district not engaged in generation, transmission or distribution as of 1/13/77 unless no other pol. subdivision, coop or IOU is willing to enter into sale or exchange upon equally favorable terms.	Power to issue only revenue bonds.
Minnesota (Minn. Stat. §§453.51--453.62)	Any 2+ Minn. cities authorized to engage in distribution and sale of energy may form municipal power agency by execution of agency agreement authorized by resolutions of governing bodies.	Agreement must be filed w/Sec'y of State who issues cert. of incorp. if agreement conforms to Act. Cities cannot join w/ IOU's, coop's or other pol. subdivisions.	General powers/ excluding distribution/ plus acquisition of fuel deposits and operation of facilities to extract, store and transport fuel/plus acquisition of interest in or capacity share of any elec. facility.	General powers/ excluding distribution.	General powers.

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	None.	No state regulation of rates but Mass. Dept. of Public Utilities has juris. over securities issuance. Also subject to regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of other utilities except for purpose of acquiring property or rights to permit crossing of existing transmission or distribution facilities.	Property, income, existence or franchise exempt, but must pay to appropriate property taxing authorities amounts which would be assessable if property were owned by an IOU.	Indebtedness, interest and income therefrom exempt.
Standard security arrangements/ plus obligations may be secured by taxes, special assessments or charges.	50-year maximum term on obligations; maximum discount of 10% of par value.	No state regulation of rates, but Mich. Municipal Finance Commission must approve bonds and other obligations to repay advances made or to pay for property delivered to agency. The pledge of special assessments lawfully imposed by members or by state and then paid to jt. agency pursuant to law or contracts may be debts of the State of Michigan or members.	Power of eminent domain, but cannot condemn existing private generation or transmission facilities w/o approval of lawful private owner.	Property, income, existence or franchise exempt from general or special taxes.	Indebtedness, interest and income therefrom exempt.
Standard security arrangements/plus obligations may be secured by mortgage of or pledge of security interest in property of jt. agency.	None.	No state regulation of rates or securities issuance, but agency not exempt from regulation of construction or operation of GT facilities.	Property exempt.	Jt. agency must pay to each appropriate taxing authority the amounts which would be assessable were property owned by private person.	Interest on indebtedness exempt from income taxes, but no general exemption of obligations from property taxation.

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State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
Mississippi (Miss. Code of 1972, Tit. 77, Art. 15)	Any 2+ Miss. cities, towns or other units of municipal gov't which own elec. systems or facilities may create jt. agency by adoption of resolution or ordinance by governing bodies.	Municipalities cannot join with IOU's, coop's or some other pol. subdivisions.	General powers/ excluding distribution/ plus power to acquire fuel deposits and acquire or construct facilities for extraction, conversion, transportation and storage of fuel. Acquisition of an interest in system or facility subject to appeal by any objecting person.	General powers/ excluding distribution.	General powers, but private sale of bonds must be justified to Governor, Chrmn. of House Ways and Means Comm. and Senate Finance Comm.
Missouri (Jt. Municipal Utility Commission Act)	Any 2+ Mo. municipalities may contract to establish a jt. municipal utility commission.	Municipalities cannot join w/IOU's, coop's or other pol. subdivisions.	General powers/ plus power to acquire fuel deposits and acquire or construct facilities for extraction, conversion, transportation and storage of fuel/excluding power to erect, own, use or maintain transmission line w/in 2 miles of existing line which serves same area, unless authorized by Mo. Public Service Commission.	General powers/ excluding authority to sell power at retail outside boundary limits of members.	General powers/ plus power to issue interim certificates.
New Hampshire (1977 N.H. Session Laws, Ch. 238)	Any 2+ N.H. pol. subdivisions, pol. subdivisions of adjacent state and quasi-municipal corporations may create separate pol. entity to provide services and facilities which each member authorized to provide separately by adopting ordinances or resolutions.	Agreement must be approved by A.G. and by officers or agencies of N.H. who control provision of services or facilities authorized under the agreement. Pol. subdivisions cannot join w/ IOU's or coop's.	May exercise any power common to all contracting entities.	No prov.	Jt. agency not authorized to issue bonds, notes or other obligations, but participating entities may in manner specified in agreement.

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	Highest permissible interest rate on obligations is 8% per annum; lowest rate may not be less than 70% of highest rate borne by other bonds or notes of same issue. Jt. agency may not issue obligations unless issuance approved by governing bodies of members.	No state regulation of rates or securities issuance. No permit, license or cert. of approval required from Miss. Public Service Commission.	Power of eminent domain, but cannot condemn property owned by other utilities; lines and rights-of-way of such entities may be crossed by jt. agency.	Property purchase, exchange of capacity, transmission of power for resale and sales of power exempt.	Indebtedness and interest and income therefrom exempt from taxation, except gift, estate or inheritance taxation.
Standard security arrangements/plus power to mortgage, pledge or grant security interest in property of jt. agency.	Obligations must be sold at public sale, unless jt. agency rejects all bids at public sale. Issuance must be approved by members' electorates, which elections cannot be held until feasibility rept. has been prepared by independent consulting engineers.	Rates and securities issuance subject to regulation by Mo. Public Service Commission.	Power of eminent domain, but cannot condemn properties of other utilities.	All property subject to taxation by appropriate taxing authorities to some extent as public utilities.	Indebtedness, interest and income therefrom exempt from taxation, except estate, inheritance and transfer taxation.
No. prov.	Participating entities may not issue obligations to finance current operating and maintenance expenses of jt. agency. Before issuance of obligations, governing body of town or village dist. may and, upon petition of 50 qualified voters or 25% of qualified voters, shall submit project to PUC for review.	No state regulation of rates, but securities issuance may be regulated by PUC. (See Impediments to Financing.) No prov. exempts jt. agency from regulation of construction or operation of GT facilities.	No prov.	Property not subject to ad valorem taxation.	Indebtedness, interest and income therefrom exempt from taxation.

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State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
North Carolina (N.C. Gen. Stat., Ch. 159B)	Any 2+ N.C. cities or towns which own elec. systems or facilities may create jt. agency by resolution or ordinance of governing bodies.	Application to create jt. agency must be filed w/ Sec'y of State. Municipalities cannot join w/ IOU's, coop's or other pol. subdivisions.	General powers/ excluding distribution/ plus power to acquire or construct facilities for extraction, conversion, transportation and storage of fuel/plus acquisition of interest in or capacity share of any elec. facility.	General powers/ excluding distribution/ excluding power to purchase or sell at retail/ excluding power to sell to utilities of other states, except in emergency.	General powers/ excluding power to issue obligations to refund bonds, notes or other obligations previously issued.
North Dakota (1977 N.D. Session Laws, Ch. 384)	Any 2+ N.D. cities authorized to engage in local distribution and sale of energy may contract to form municipal power agency by resolution of governing body.	Agreement must be approved by 60% of qualified electors in regular or special elections. Agreement must be filed w/Sec'y and cert. of incorp. issued. Cities cannot join w/IOU's, coop's or other pol. subdivisions.	General powers/ excluding distribution/ plus power to acquire or construct facilities for extraction, conversion, transportation and storage of fuel/plus acquisition of interest in capacity share of any elec. facility.	General powers.	General powers.
Oklahoma (Okla. Stat. Tit. 74, Ch. 31)	Any 2+ Okla. pol. subdivisions or of another state may contract to create separate legal entity by ordinance or resolution.	Agreement must be approved by A.G. Pol. subdivisions cannot join w/ IOU's or coop's.	May exercise any power, privilege or authority that may be exercised by all participating entities.	May exercise any power, privilege or authority that may be exercised by all participating entities.	Jt. agency not authorized to issue bonds, notes or other obligations, but participating entities may as specified in agreement.
Oregon (Ore. Rev'd Stat. §§262.005--262.105)	Any 3+ Ore. cities or people's utility districts (PUD's) may form jt. operating agency upon adoption of membership ordinance by respective legislative bodies.	Creation must be approved by voters of each city of district and by Director of Ore. Dept. of Energy. Cities or PUD's cannot join w/ IOU's or other pol. subdivisions.	May not exercise general powers alone, or as managing participant, excluding power to lease. May not own more than 50% of plant, system or facility (except combustion turbines), involve itself in any facility for uranium refining, or acquire or operate distribution facilities.	General powers/ plus power to purchase, sell, interchange or wheel power w/ U.S. or agency thereof.	General powers/ plus power to issue bond anticipation notes.

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	50-year maximum term on obligations.	No state regulation of rates, but securities issuance regulated by N.C. Local Gov't Commission. Jt. agency which intends to issue bonds must get cert. of public convenience from N.C. Utilities Comm. No prov. exempts jt. agency from regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of other utilities. N.C. Utilities Comm. can authorize crossing of lines or rights-of-way by jt. agency.	Property exempt, but jt. agency required to pay appropriate taxing authorities amounts assessable by N.C. Dept. of Revenue. In lieu of franchise tax, must pay 6% of gross revenues, less amounts paid to purchase power and amounts sold to other taxed vendors.	Indebtedness, interest and income therefrom exempt from taxation, except inheritance and gift taxation.
Standard security arrangements. Mortgaging or executing deeds of trust of property or franchise subject to approval of not less than 60% of qualified electors of each member voting in regular or special session.	Unless agency agreement provides otherwise, obligations of jt. agency must be approved by 60% of qualified electors of each member voting in regular or special election.	No state regulation of rates or securities issuance, but no prov. exempts agency from regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of other utilities.	Property exempt, but jt. agency required to pay to each appropriate taxing authority the amount which would be payable if property were owned by private person.	Interest on obligations exempt from income taxation, but no exemption of obligations from property taxation.
No prov.	(See Issuance of Indebtedness.)	No state regulation of rates or securities issuance, but no prov. exempts agency from regulation of construction or operation of GT facilities.	No power of eminent domain, although participating entities may.	All property owned by counties or municipalities exempt from ad valorem taxation.	No prov.
Standard security arrangements.	None.	No state regulation of rates or securities issuance, but no prov. exempts agency from regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of other utilities, except to obtain rights-of-way.	All property assessed and taxed in same manner as similar property owned by private corporations, other than coop's, which taxes are deemed operating expenses of agency.	Indebtedness and interest and income therefrom exempt.

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State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
South Carolina (1978 S.C. Session Laws, Act 473)	Any 2+ S.C. cities or towns may form jt. agency by adoption of resolutions or ordinances.	Members must have owned GTD facilities for at least 10 yrs. Each member must be located w/in area generally served by S.C. Public Service Authority or any utility owning and operating nuclear facilities, but not any combination thereof. Municipalities cannot join w/IOU's or other pol. subdivisions.	General powers/ excluding distribution, to be exercised after jt. agency has purchased or leased a 10%+ interest in an existing system or facility which generally serves area in which jt. agency located and authorized to do business.	General powers/ excluding distribution, but only for resale; and only after excess capacity has been offered first to utility owning and operating a nuclear facility and serving area in which jt. agency located. Capacity available for sale to 3rd parties is capacity in excess of such elec. utility and jt. agency required to maintain specified level of reserves.	General powers.
South Dakota (1978 S.D. Session Laws, Ch. 66)	Any 2+ S.D. cities may contract to form municipal power agency by resolution of governing bodies.	Agreement must be filed w/Sec'y of State and cert. of incorp. issued. Cities cannot join w/IOU's, coop's or other pol. subdivisions.	General powers/ excluding distribution/ plus power to buy from or sell to any person, public agency, corporation, or partnership inside or outside S.D.	General powers/ excluding distribution.	General powers.
Texas (Tex. Rev'd Civ. Stat. Art. 1435a, 4a)	Any 2+ public entities may create municipal power agency upon approval of majority of qualified electors or entities and adoption of concurrent ordinances.	Entities must have been authorized to engage and be engaged in GTD for sale to the public on 5/8/75.	General powers/ excluding power to lease/excluding distribution/ plus powers incidental to GT, including power to acquire fuel deposits and acquire or construct facilities for extraction, conversion, transportation and storage of fuel/ plus acquisition of interest in or capacity share of any elec. facility.	May purchase from any entity authorized to and engaged in GTD for sale to public and may sell only to participating entities or private entities which are jt. Tx. project owners.	General powers.

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrancements.	None.	No state regulation of rates or securities issuance, but acquisition of facilities must be approved by S.C. Public Service Commission. Commission must issue cert. of environmental compatability and public convenience and necessity before jt. agency constructs facilities.	Power of eminent domain, but cannot condemn properties cf other utilities.	Project not exempt from ad valorem taxes and other taxes applied to sale of energy. If jt. agency exempt from taxation, must make payments in lieu of taxes to any appropriate taxing authority as if system or facilities were subject to valuation and assessment.	Indebtedness and interest and income therefrom exempt from taxation, except inheritance estate and gift taxation.
Standard security arrangements/plus power to mortgage, pledge or grant a security interest in any agency property.	None.	No state regulation of rates or securities issuance, but no prov. exempts agency from regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of utilities.	Property exempt, but jt. agency required to pay to each appropriate taxing authority the amount which would be payable if property were owned by a private person.	Indebtedness and interest and income therefrom exempt from taxation.
Standard security arrangements.	Maximum interest rate of 10%.	State has reserved right to regulate rates and charges of jt. agency, subject to rights of bond holders. A.G. must approve securities issuance, and comptroller must register securities. No prov. exempts agency from regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of utilities.	Agency exempt from ad valorem taxation.	No general statutory exemption of indebtedness from property taxation.

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State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
Utah (Utah Code §§11-13-1--11-13-24)	Any 2+ Utah cities, towns, counties or agencies may contract to create separate entity to provide municipal services and facilities by resolution of governing bodies.	A.G. must approve agreement before effective. For a 30-day period after publication of resolution, any interested person may contest legality of resolution. Cities, towns, counties or agencies cannot join w/IOU's or coop's.	General powers/ excluding distribution/ excluding power to lease/ plus acquisition of interest in or capacity share of any elec. facility.	May sell to any pol. subdivision of Utah or any other state or agency of Utah or U.S. provided that at least 25% of energy output is available for use within Utah.	General powers/ excluding power to issue refunding bonds, notes or other obligations.
Vermont (Vt. Stat. Tit. 30, Ch. 84)	Vt. Public Power Supply Authority consists of Vt. cities, towns and villages with GTD facilities and coop's which by 1/31/79 elected to become members of Vt. Public Supply System, Inc.	Other towns, cities, IOU's, and coop's may become members of jt. agency in accordance with rules of agency.	General powers/ excluding distribution/ plus power to contract with coop's, municipal utilities and private utilities who are not members of Authority. Vt. city, town or village cannot contract with Authority w/o affirmative vote of electorate at annual or special meeting.	General powers with regard to surplus power/ excluding distribution.	General powers/ plus power to issue stock.
Virginia (Va. Code, Tit. 15.1, Ch. 37)	Any 1+ Va. cities or towns owning facilities for GTD, any incorporated Va. city having a population of 200,000+ on 1/1/79 and any Va. county or incorporated city or town which after 1/1/79 is authorized by Va. General Assembly to participate in an elec. authority may create an elec. authority by concurrent ordinances.	Va. State. Corp. Commission must issue articles of incorporation to validate creation. Cities, towns or counties cannot join with IOU's, coop's or other pol. subdivisions. No governmental unit may participate without affirmative vote of electorate.	General powers/ excluding distribution/ plus power to enter into jt. ownership contracts with coop's, other public or private utilities, other agencies or pol. subdivisions of other states or of the U.S.	General powers/ excluding distribution.	General powers.

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	Before adopting bond resolution, jt. agency must offer to enter into power sales contract for 50%+ of energy output with suppliers of energy within Utah who were furnishing service on 7/1/77.	No state regulation of rates or securities issuance, but entity must obtain cert. of public convenience and necessity from Utah Public Sercice Commission.	No express authorization.	Property exempt from ad valorem taxation, but power sold subject to sales and use taxes. Must pay to each appropriate taxing authority the amount which would be payable if property owned by private person plus annual fee on assessed valuation of % of property being used to produce sales outside Utah.	Interest on indebtedness exempt from personal income taxation, but no exemption of obligations from property taxation.
Standard security arrangements/plus power to pledge, mortgage or grant a security interest in any real or personal property of Authority.	None.	No state regulation of rates or securities issuance, but Authority is subject to regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn properties of other utilities, except to obtain rights-of-way.	Property, activities, revenues and income exempt from ad valorem taxation, franchise fees and special assessments. Jt. agency required to pay to each appropriate taxing authority the amount which would be payable if property were owned by private person.	No exemption of interest from income, transfer, inheritance and estate taxation.
Standard security arrangements.	None.	No state regulation of rates or securities issuance, but Va. State Corp. Comm. must issue cert. of public convenience for construction, acquisition or enlargement of GT facilities.	Power of eminent domain, but cannot condemn existing power supply facilities. Unless special court convened, cannot exercise power outside territorial limits of members without consent of governing body.	Property exempt from ad valorem taxes, but jt. agency required to pay to each appropriate taxing authority the amount which would be payable if property were owned by private person. Also required to pay franchise tax.	Indebtedness and interest and income therefrom exempt from taxation, except transfer, inheritance and estate taxation.

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State	Membership Organization	Impediments to Creation	Ownership and Operation of Facilities	Purchases and Sales of Power	Issuance of Indebtedness
Washington (Wash. Rev'd Code, Ch. 43.52)	Any 2+ Wash. cities or towns or public utility districts (PUD's) may form jt. operating agency to undertake specific projects by resolution.	Application must be filed with Dir. of Ecology of State of Wash. Notice of creation must be published. Public utility may object to creation within 10 days and the Dir. may hold a public hearing. Dir.'s order may be appealed. Cities, towns or PUD's may not join with IOU's, coop's or other pol. subdivisions.	General powers/ excluding distribution/plus power to enter jt. ownership contracts with the U.S. or its agencies or any city, town or PUD/plus power to construct facilities for conversion, transportation and storage of fuel. Jt. operating agency cannot undertake projects in addition to those for which it was formed without approval of leg. bodies of majority of members.	General powers/ excluding distribution/ but members have preference right to purchase all elec. energy.	General powers, but must invite bids before trying to sell bonds at private sale.
Wisconsin (Laws of 1977, Ch. 159)	Any 2+ Wis. cities, villages or towns may contract to establish municipal electric company.	Municipalities cannot join with IOU's, coop's or other pol. subdivisions.	General powers/ plus power to construct facilities for conversion, transportation and storage of fuel/plus acquisition of interest in or capacity share of any elec. facility.	General powers. Jt. agency cannot sell at retail unless authorized to do so by member.	General powers/ plus power to issue interim certificates.
Wyoming (Wyo. Stat. §§9-18.13--9-18.20)	Any 2+ Wyo. municipalities may contract to create jt. powers board by execution of agreement of governing bodies.	Participants must have owned GTD facilities prior to 3/1/75. Agreement must be approved by A.G. Municipalities cannot join with IOU's, coop's or other pol. subdivisions.	General powers/ but only facilities for service to and use by participating municipalities and their resident customers.	May buy from and sell to only participating municipalities and residents.	Power to issue only revenue bonds.

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Security for Indebtedness	Impediments to Financing	State Regulation	Eminent Domain	Taxation/ Payment in Lieu of Taxes	Taxation of Securities
Standard security arrangements.	None.	No state regulation of rates or securities issuance, but is subject to regulation of construction or operation of GT facilities.	Power of eminent domain, but cannot condemn existing power supply facilities.	Entity exempt, but jt. agency required to pay to each appropriate taxing authority the amount of tax revenues being received by entity at the time of acquisition or construction of facilities. Payments not required for nuclear facility constructed or acquired by jt. agency prior to 5/17/71.	Indebtedness, interest and income therefrom exempt from taxation.
Standard security arrangements/plus power to mortgage or grant security interest in any real or personal property of the company.	None.	No state regulation of rates or securities issuance, but subject to regulation by Wis. Public Service Commission of construction or operation of GT facilities.	Power of eminent domain, subject to approval of Wis. Public Service Commission, but cannot condemn existing power supply facilities.	Jt. agency and property exempt, but jt. agency must make payments to state in amounts which would be paid if it were a public utility under state law.	No exemption of obligations or interest from property or income taxation.
Standard security arrangements.	Net interest rate on indebtedness cannot exceed 10% per annum.	No state regulation of rates or securities issuance, but is subject to regulation of construction or operation of GT facilities.	No prov.	No exemption from ad valorem taxation.	Indebtedness, interest and income exempt from taxation.

APPENDIX D
TMPA
A JOINT AGENCY CASE HISTORY

1.0 INTRODUCTION TO TMPA

1.1 Agency Overview

The Texas Municipal Power Agency (TMPA) was created in July 1975 by concurrent ordinances of the Texas cities of Bryan, Denton, Garland and Greenville. TMPA is a separate municipal corporation, a political subdivision of the State.

TMPA was created to act on behalf of the four Cities for the purpose of obtaining the economic advantages of jointly financing, constructing and operating large electric generating units and related facilities to supply the Cities' future energy into the nuclear and lignite fuel markets. They were responding directly to the rising costs of natural gas and oil.

Since 1975, the agency has issued $600 million in revenue bonds providing partial funding for:

- The construction of a 400 megawatt lignite-fired generating plant (Gibbons Creek, Unit No. 1);
- The purchase of 6.2 percent interest in each of two 1150 megawatt nuclear-fueled units (Comanche Peak, Units No. 1 and No. 2); and
- Certain required transmission facilities.

TMPA is the first joint agency formed in Texas. In four separate legal actions, the constitutionality and validity of the agency, its enabling legislation and its contracts with its four member cities have come under attack. To date TMPA has been upheld in court; however, the lawsuits have been significant events in TMPA's history and will be described at greater length in sections following.

1.2 Case History Method

This case history is the result largely of interviews. Separate meetings were held with the following individuals:

- Mr. Larry C. Hearn, P.E., Director of Engineering and Operations, Texas Municipal Power Agency;
- Mr. Gailord M. White, P.E., Director of Electric Utilities, City of Bryan, Texas;
- Mr. R. E. (Bob) Nelson, P.E., Director of Utilities, City of Denton, Texas (former Director of Utilities, City of Greenville, Texas);
- Mr. E. B. (Ernie) Tullos, P.E., Assistant Director of Utilities, City of Denton, Texas;
- Mr. Bob Corder, P.E., Director of Electric Utilities, City of Garland, Texas;
- Mr. J. Louis Odle, P.E., City Manager, Kerrville, Texas (former City Manager, Bryan, Texas, 1974-1978).

Additional information was obtained through a system compliance option meeting in Denver, Colorado on April 2, 1980, held by the Department of Energy's Office of Fuels Conversion for the Cities of Denton and Bryan.

2.0 INTRODUCTION TO THE MEMBER CITIES

2.1 Description of the Member Cities

The Cities of Bryan, Denton, Garland and Greenville are shown in Figure I. Relevant information about each of the Cities and their municipally-owned electric utilities is summarized, as follows.

Bryan is the county seat for Brazos County, and is located about 100 miles northwest of Houston. The U.S. Bureau of the Census estimated the 1975 population to be 37,160, an increase of 10.2 percent from the 1970 Census and 34.9 percent from the 1960 Census figures.

The Bryan electric system has one generating plant with six gas-fired steam turbine generating units and one combustion turbine generator. A new gas-fired stem turbine generating unit having a capability of 100 MW was put into commercial operation in May 1978 and gives the City an aggregate capability of 240 MW.

The City of Bryan, in addition to its municipal system, owns and operates a distinct and separate rural transmission and distribution system which purchases electric energy from Bryan's municipal system.

Denton is the county seat for Denton County, and is located 38 miles northwest of downtown Dallas. The U.S. Bureau of the Census estimated the 1975 population to be 43,499, an increase of 9.1 percent from the 1970 Census and 62.0 percent from the 1960 Census figures.

The Denton electric system has five diesel generating units and five gas-fired steam turbine units with an aggregate capability of 168 MW.

Garland is located approximately 14 miles northeast of downtown Dallas. The U.S. Bureau of the Census estimated the 1975 population to be 111,322, an increase of 36.7 percent from the 1970 Census and 189.1 percent from the 1960 Census figures.

The Garland electric system has two gas-fired steam generating plants and one diesel generating plant having an aggregate capability of 424 MW.

Texas Power & Light Company has operated in Garland since 1915, and currently serves about 15 percent of the electric customers in the City.

Greenville is the county seat for Hunt County, and is located 45 miles northeast of the City of Dallas. The U.S. Bureau of the Census estimated the 1975 population to be 20,907, a decrease of 5.4 percent from the 1970 Census, but an increase of 9.5 percent from the 1960 figures.

The Greenville electric system has three gas-fired steam turbine generating units and eight gas-fueled diesel electric generator for use during periods of peak demand. The aggregate capability of the Greenville system is 100 MW.

2.2 The Member Cities as a Single System

The aggregate generating capacity of the municipal electric systems of the Cities is 932 MW. In fiscal 1978 the Cities provided electric service to approximately 75,300 customers. Revenues derived from sales of electricity in fiscal 1978 were approximately $93 million and system energy requirements were in excess of 2.3 billion kWh (see Table I).

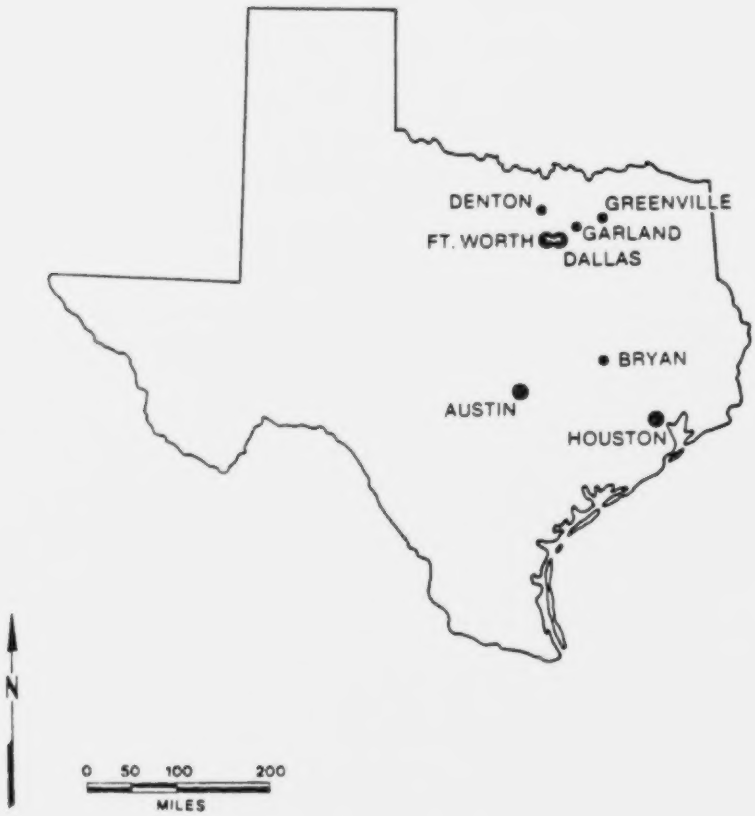
DENTON
GREENVILLE
GARLAND
FT. WORTH
DALLAS
BRYAN
AUSTIN
HOUSTON
N
0
50
100
200
MILES

Figure 1. Location map

TABLE I. RECENT ELECTRIC UTILITY OPERATING STATISTICS: TMPA MEMBER CITIES

	1974	1975	1976	1977	1978
CITY OF BRYAN					
Average number of customers					
Residential	9849	11266	11817	13109	14073
Industrial & Commercial	1651	1715	1782	1864	1948
Other	4	4	164	177	178
Total customers	11504	12985	13763	15150	16199
Kilowatt-hour sales					
Residential	99575	101940	112975	125447	151074
Commercial & Industrial	126922	123461	136855	133372	146435
Other	191441	213519	226989	216727	177056
Total sales	417838	438920	476819	495553	474565
Average cost (mills/kWh)	15.8	20.0	26.8	35.9	39.9
CITY OF DENTON					
Average number of customers					
Residential	10850	11000	11587	12445	12831
Commerical & Industrial	1820	2038	2254	2410	2603
Other	273	273	283	312	310
Total customers	12952	13341	14124	15167	15844
Kilowatt-hour sales					
Residential	106231	105203	112702	133951	148923
Commercial & Industrial	251315	276168	288156	295017	302674
Other	20060	21105	18319	21960	23106
Total sales	378532	402476	419177	450928	474703
Average cost (mills/kWh)	17.7	22.8	29.8	37.3	40.7
CITY OF GARLAND					
Average number of customers					
Residential	25096	26474	27333	29770	31970
Commerical & Industrial	2072	2061	2077	2257	2378
Other	2	2	2	2	2
Total	27170	28537	29412	32029	34350
Kilowatt-hour sales					
Residential	399602	456158	422060	508007	575186
Commercial & Industrial	417604	466969	507052	555073	571416
Other	21059	25670	50677	63271	65644
Total sales	838265	948797	979789	1126351	1212256
Average cost(Mills/kWh	17.5	22.7	26.8	30.3	32.0
CITY OF GREENVILLE					
Average number of customers					
Residential	8015	7636	7666	7651	7861
Commerical & Industrial	1035	960	1039	1037	1049
Other	0	50	60	67	69
Total	9050	8646	8765	8745	8968
Kilowatts-hour sales					
Residential	64019	64150	61341	73905	78777
Commerical & Industrial	98567	103700	110316	127174	131334
Other	3326	11577	7770	5938	7030
Total sales	165812	179427	179427	207013	217101
Average cost(Mills/kWh)	20.8	26.7	32.2	38.2	42.3

The percentage that each City's system load bears to the aggregate system load of the four Cities (as projected through fiscal 1982) is, as follows:

City of Bryan	18 Percent
City of Denton	21
City of Garland	52
City of Greenville	9
Total	100 Percent

Most of the generating facilities of the Cities use natural gas as the primary fuel. The Cities' supplier of natural gas is Lone Star Gas Company ("Lone Star"). On November 7, 1977, the Cities entered into take-or-pay gas purchase agreements, replacing prior agreements, with Lone Star which expire on December 31, 1984, and a gas transfer agreement between themselves and Lone Star which permits the Cities to transfer gas purchased from Lone Star among themselves.

Although the Cities have individual contracts, they negotiated collectively in order to secure the gas transfer agreement essential to their econimic dispatch conservation program. Under the gas transfer agreement, any City may take delivery of its gas at any generating unit controlled by a member City. This means the most efficient unit available will always be dispatched first.

Lone Star, initially reluctant to agree to gas transfer, has been pleased to find the program of benefit to its own operation, permitting the gas company to transfer delivery points at critical times. Gas transfer agreements will probably be considered attractive by all parties to future Lone Star/Member City contracts.

Under the Lone Star agreements, deliveries are subject to curtailment. The agreements require the Cities, 27 months in advance, to make preliminary estimates of their natural gas fuel requirements for each year. One year later, the Cities make final revisions of such requirements. The agreements contain maximum and minimum limits within which preliminary estimates and final determinations must be made. These limits may make it difficult for the Cities to take all the gas needed from Lone Star to avoid a take-or-pay penalty when Gibbons Creek and Comanche Peak commence commercial operation. Conversely, additional natural gas supplies may be needed by the Cities if those projects should be delayed.

Virtually all generating units operated by the four Cities are capable of burning either No. 6 or No. 4 fuel oil, at least on a standby basis. Each City has limited fuel oil storage facilities. The aggregate storage capacity available to the Cities is approximately 430,000 barrels. The aggregate generating capability of units using fuel oil on a continuous basis is 324 MW.

Although dual firing capabilities have given the Cities added flexibility in the petro-fuels market, and short-term alternatives for FUA compliance, both fuels are subject to substantial price increases. Their long-term economic viability is so substantially in doubt that it provided the major stimulus for the formation of TMPA to develop generation capabilities using alternative fuels. The four Cities have entirely suspended their expansion of oil and natural gas capacity and have entrusted all of their future capacity growth to TMPA.

The Cities' aggregate energy requirements and the available energy resources through the year 1988 as projected by the Cities are summarized in Table II. In 1981 and thereafter, the agency's and the City-owned units would normally be operated only after Comanche Peak and Gibbons Creek are loaded, or if one of these units is temporarily inoperative or if sales of reserve capacity and/or energy are made to others. As an example, in 1984, the forecase cost of fuel per million Btu is \$3.70 for natural gas; \$1.21 for lignite; and \$0.61 for nuclear. Accordingly, in the "Load Rsource Balance" column of the preceding table, the capacity indicated to be in excess of requirements is expected to be essentially in the existing City-owned generating units, although the energy demands of the Cities' systems require a load reduction at Gibbons Creek during some minimum load conditions. This is only true for the first few years of operation.

TABLE II. FORECAST PEAK LOADS AND RESOURCES (MW)

	REQUIREMENTS				RESOURCES				LOAD RESOURCE BALANCE
						TMPA			
YEAR	CITIES' PEAK REQUIREMENTS	TRANSMISSION LOSSES	15% RESERVES	TOTAL REQUIREMENTS	CITIES' RESOURCES	GIBBONS CREEK	COMANCHE PEAK	TOTAL RESOURCES	
1979	616	*	92	708	932	0	0	932	224
1980	660	*	99	759	932	0	0	932	173
1981	694	21	104	819	932	0	71	1003	194
1982	736	22	110	868	932	400	71	1403	535
1983	784	24	118	926	932	400	142	1474	548
1984	829	25	124	978	932	400	142	1474	496
1985	873	26	131	1030	932	400	142	1474	444
1986	922	28	138	1088	932	400	142	1474	386
1987	971	29	146	1146	932	400	142	1474	328
1988	1021	31	153	1205	932	400	142	1474	269

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The figures in Table II reflect the four Cities' projections of January 1979 and are based on an annual average growth rate of combined peak loads of 5.77 percent.

3.0 TMPA ENABLING LEGISLATION

3.1 Legislative History

TMPA has a short legislative history. The Texas Municipal Power Act (Chapter 166, Acts of the 63rd Legislature of Texas, Regular Session 1973, as amended by Chapter 143, Acts of the 64th Legislature, Regular Session 1975 and codified in Vernon's Revised Civil Statutes as Article 1435a, 4a) was passed in 1975, without debate, by unanimous vote of both houses of the Texas Legislature.

Senators Tom Creighton (D-Mineral Wells) and Bill Moore (D-Bryan), principal sponsors of the bill, presented it as a measure enabling the four Cities to stay in the public power business by buying into Texas Utilities' Commanche Peak nuclear plant. Nothing was said about the lignite leasing and exploration program being carried out by the Cities with Brazos Electric Power Cooperative, or their plans for a pair of 400-megawatt lignite plants at Gibbons Creek in Grimes County, Texas. The Act was drafted with assistance from Denton, Garland, Greenville and Bryan officials, together with attorneys for Brazos Electric Power Coop in Waco and an informal committee of engineers, bond lawyers and private financial firms (First Southwest Company of Dallas and Duhn Loeb & Company of New York).

Several interviewees expressed the opinion that backing for the bill from the investor-owned utilities (IOU's) is at least partially explained by their desire to satisfy NRC anti-trust review of the Comanche Peak nuclear power station. A joint agency could provide the funding required for small municipally-owned utilities to participate in such a project, and the NRC antitrust review was thought to require such small utility participation.

Prior to submission to the Texas legislature, a draft of the legislation was submitted to lobbyists for Texas IOU's for their review. Some changes in the legislation were made as a result. For example, participation by municipalities was limited to those which were "engaged in the generation of electric energy for sale to the public upon the effective date of this Act," May 3, 1975. The change meant that no municipal utilities not already generating their own power could use the legislation as a means of entering into competition with IOU's. Another change limited the market to which a joint agency would be able to sell the power it generated. Such an agency "shall not be authorized to engage in any utility business other than generation, transmission and sale or exchange of electric energy to the participating public entities and to private entities who are joint owners with the agency of an electric generating facility within the state" (emphasis added).

During the short legislative process, a rider was added to the bill which may also have been inspired by IOU lobbyists: Senator Creighton introduced two minor changes, requiring voter approval for decisions by public bodies to create joint agencies after January 1, 1977, or to join an existing agency after April 1, 1976. These stipulations could have the effect of protecting IOU's against a proliferation of joint agency competitors. The January 1, 1977, deadline provided time for the four Cities to create TMPA through concurrent ordinances without holding general elections.

What emerged was relatively strong joint agency enabling legislation acceptable to the IOU's and in no way limiting the options of the four Cities who were hoping to create the first joint agency in Texas.

3.2 Statutory Organization and Powers

The four Cities acted promptly on July 18, 1975, by passing concurring ordinances which created TMPA. The agency is a municipal corporation, a political subdivision of the State of Texas and a body politic and corporate, governed by a Board of Directors consisting of eight members who serve without compensation. The governing body of each of the four Cities appoints two members to the Board. Terms of members are two years, with the term of one representative from each City expiring annually, resulting in staggered terms. An affirmative vote of five Directors, plus a weighted majority vote based on the respective energy usage of the Cities, is required for certain major decisions under the provisions of the Agency's Rules and Regulations. The fact of creation under the concurring ordinances gave TMPA certain statutory powers briefly described.

3.2.1 Own and Operate Facilities

A municipal power agency, such as TMPA, may plan, acquire, construct, own, operate and maintain any facilities necessary or incidental to the generation and transmission of electric power. A municipal power agency may jointly own and operate such facilities with any other public or private entity engaged in the generation, transmission or distribution of electric energy for sale to the public. A municipal power agency is not authorized to engage in the distribution of electric power directly to the public.

3.2.2 Purchase, Sell, Exchange and Pool Power

A municipal power agency may purchase electric energy from any entity authorized to and engaged in the generation, transmission or distribution of electric energy for sale to the public. A municipal power agency is authorized to sell or exchange electric energy to participating public entities and to any private entities which are joint owners with the municipal power agency of an electic generating facility located within the State of Texas. A municipal power agency may participate through appropriate contracts in power pooling and power exchange arrangements with public and private entities either through direct or indirect system interconnections.

3.2.3 Power of Eminent Domain

A municipal power agency may acquire lands, easements and properties necessary for its purposes by the exercise of the power of eminent domain. A municipal power agency, however, has no power to take by eminent domain any electric facilities or interest therein belonging to any other entity, nor may the power of eminent domain be exercised to secure fuel stocks through condemnation of mineral rights.

3.2.4 Power to Issue Bonds

A municipal power agency has the power to issue bonds for indebtedness and to pledge the agency's "Net Revenues" to the payment thereof.

3.2.5 Other Borrowing Powers

A municipal power agency is authorized to issue bond anticipation notes for the purposes for which the bonds may be issued. The Act also permits the issuance of non-negotiable purchase money notes payable in installments (secured by the properties being acquired) in order to acquire land or fuel resources.

3.2.6 Rate Making Power

A municipal power agency sets its own rates and charges. The State has retained authority to regulate and control rates but, as a practical matter, the State has not exercised reserve authority through the State Public Utilities Commission or other agency.

3.2.7 Freedom from State Taxes

Texas law provides that an entity of the character of a municipal power agency is exempt from ad volorem taxes and all other taxes, including, but not limited to, excise, sales, and use taxes, imposed by the State of Texas on private utilities. The Act does not provide for a municipal power agency to make payments in lieu of taxes.

3.2.8 Power to Contract with Members

A municipal power agency may enter into contracts with its Cities with respect to the sale and purchase of electrical energy. Substantial powers may be derived from the Cities through the contractual process. TMPA's powers as a result of its contracts with the member cities are discussed in the following subsection.

3.3 TMPA Contractual Powers

TMPA has entered into an identical Power Sales Contract (the "Contract") with each of its member cities. The Contract will remain in effect for a period of thirty-five years from September 1, 1976, the effective date, or until all bonds are paid, whiichever occurs later.

The Contract obligates TMPA to use reasonable diligence to provide a constant and uninterrupted supply of power and energy to the Cities and, subject to the exceptions set forth in the Contract, obligates the Cities to purchase from the Agency, if available, all of the Cities' power and energy requirements in excess of the amounts generated by the Cities' existing municipal systems. All amounts payable by the Cities under the Contract are payable solely from the revenues of their respective electric systems and constitute operating expenses thereof, and are not payable from taxes or any other revenues of the Cities.

Under the Contract, the Cities must approve any "Project" before TMPA is authorized to proceed with the financing, construction, equipment procurement or development of the facility. After approval by the Cities, TMPA may proceed with the general management of the Project as it deems appropriate. Additionally, TMPA may make "System Development and Reliability Expenditures" as "Approved Projects" for facilities and purposes when authorized by the Cities.

With certain limited exceptions, the Contract requires each City to purchase from TMPA all of the power and energy required for the operation of its electric system in excess of the amount (i) supplied by any generation and transmission facilities owned by it on October 7, 1976, and (ii) supplied from any generating facility constructed and owned by one or more of the Cities and primarily fueled from and the construction and operation of which is incidental to the disposal of solid waste. The Cities are also free to purchase or exchange power and energy with others than the Agency (A) on an emergency, maintenance or standby basis, (B) on the basis of economic dispatch between the Cities and Brazos Electric Power Cooperative (BEPCO) or any one or more of such entities, or (C) under the existing pooling agreement between the Cities and BEPCO and future pooling agreements among them and others, or any combination thereof, and TMPA. The Contract also requires or allows TMPA to perform certain other services for the Cites. These include comprehensive planning, and undertaking or coordinating design and economic dispatch.

The Contract prohibits any member city from disposing of any of its power plants without the approval of TMPA and the other member cities.

4.0 TMPA HISTORY

4.1 Joint Efforts Preceding TMPA

The idea for TMPA grew out of an informal power pooling agreement existing since the 1950's between Brazos Electric Power Cooperative (Brazos) and three of the current TMPA members, Bryan, Garland and Greenville. In 1963 the four entities entered an "Interchange Agreement" forming the "Texas Municipal Power Pool." City of Denton joined the pool in 1969. The pool was formed after a study by R. W. Beck and Associates showed substantial savings were achievable through coordinated operations when compared to costs for continued individual system operations. The Interchange Agreement established management procedures and provided for coordination of capacity of spinning reserve, as well as for the purchase and sale of supplemental and emergency power. Procedures also provided for cost sharing of jointly used facilities and a "take your turn" formula for additions to new generating capacity. Original TMPP studies indicated that fixed cost savings would amount to approximately $8.5 million during the first 10 years of pool operation. Recent costs comparisons completed by TMPP staff have confirmed those estimates in fact. The Texas Municipal Power Pool continues to exist and to function under the 1963/1969 Interchange Agreement between and among TMPA member cities and Brazos Electric Power Cooperative will be clarified. The new Interchange Agreement between and among TMPA member cities and Brazos Electric Power Cooperative will be clarified. The new Interchange Agreement is likely to coincide with TMPA projects at Gibbons Creek and Comanche Peak coming on-line and will enable the TMPA system to operate at full economic dispatch. Currently, the six entities of Brazox, TMPA and the four Cities are drafting an agreement to replace the Interchange Agreement.

4.2 TMPA Litigation History

TMPA has had four major lawsuits filed against it.

A suit filed in 1977 in behalf of the Grimes County Taxpayers Association (and others) sought to stop the Gibbons Creek 400 MW lignite-fired Unit No. 1 by having the statute under which TMPA was created declared unconstitutional. The 12th Judicial District Court of Grimes County, Texas entered a summary judgment in favor of TMPA, and on March 2, 1978 the Court of Civil Appeals affirmed the trial court's decision. As a result of the settlement agreement discussed below, plaintiffs waived motion for rehearing and the decision of the Appeals Court became final. The issues in the suit were resolved in favor of TMPA.

The Grimes County Taxpayers' Association filed another suit in 1977 against TMPA and the Environmental Protection Agency (EPA) protesting the proposed issuance of a permit by the EPA to TMPA for discharging wast water from TMPA's Gibbons Creek Steam Electric Station. As in the first case, the practical objective of this suit was to force TMPA into a position where, to avoid continued litigation, it would have to forego the advantages of its privileged tax status. As a result of the settlement agreement discussed below, an agreed judgment was entered by the U.S. District Court, Southern District of Texas, denying the relief sought by the plaintiffs. The judgment is binding on all parties as the plaintiffs have waived all rights of appeal or other complaints. In order to obtain certain property and confirm certain rights necessary to complete the Gibbons Creek Stem Electric Station and to settle various controversies with certain local government units and others, TMPA entered into a settlement agreement with the Grimes County Taxpayers' Association and others on July 19, 1978. A legal proceeding in the District Court of Grimes County confirmed the terms of the settlement agreement and made those terms applicable between TMPA, the Taxpayers' Association, the County of Grimes, Texas, the State of Texas and three school districts. Under terms of the agreement TMPA, on July 19, 1978, made payments to the County and the three school districts aggregating $270,000. TMPA also agreed to make annual payments to the County and the three school districts so long as the Gibbons Creek Unit No. 1 is in operation as follows: 1979 - $320,000, 1980 - $370,000, 1981 - $420,000, 1982 and thereafter - $520,000. TMPA was also required to pay the County an amount not to exceed $500,000 for the upgrading of two county roads in 1979. Proceeds from Revenue Bonds, Series 1978 aggregating $1,610,000 have been placed in trust accounts to fund the payments due in 1979, 1980 and 1981. The payments due in 1982 and thereafter are to be made out of the gross revenue from the sale of electricity from the Gibbons Creek Steam Electric Station. The amount of annual payments to be made each year is subject to adjustments specified in the agreement. The estimated total payments to be made by TMPA under this agreement are approximately $17,000,000, including plaintiffs' legal fees and expenses of $473,000.

In exchange for these payments, the Grimes County Taxpayers' Association, the County and the three school districts settled their controversies with TMPA. The County and the school districts have agreed that TMPA is not liable for ad valorem taxes under existing Texas law and that TMPA has a power of eminent domain. The County further agreed to convey certain property to TMPA and to make available for leasing on a competitive-bid basis certain County land which is believed to contain lignite deposits.

Significant aspects of these lawsuits and the settlement may be explained as follows:

- The strongest point in the plaintiffs' favor was one of the practicality, not law. When plaintiffs filed suit alleging the unconstitutionality of TMPA's enabling legislation they forestalled TMPA's second bond issue. Bond issues require prior approval by the Texas Attorney General. Approval may be withheld so long as a lawsuit raising serious constitutional questions about the bond issue remains unresolved. Therefore the litigation, the negotiations and the procedural delays all took place while TMPA was in the process of running out of money.

- Plantiffs attacked TMPA in a variety of ways during the pending litigation. For example, they advertised in the newspapers of each of the member cities, calling attention to the existence of TMPA, its extraordinary powers to create indebtedness for the citizens, and the lack of direct voter approval. As a result, local citizen opposition to TMPA was raised in each of the member cities. People ran for city council on anti-TMPA platforms and two were elected.

- Plantiffs attacked TMPA through the legislature process. Several of the proposed opposition bills failed, but one limiting TMPA's eminent domain authority succeeded. Prior to 1977, TMPA's authority arguably may have been broad enough to have included the condemnation of lignite reserves for boiler fuel. The 1977 amendment probhbited the use of eminent domain authority for the purpose of drilling, mining or producing fuels or energy sources such as lignite. Eminent domain authority for the purpose of plant sites, cooling reservoirs and related surface installations was unaffected.

- Plantiffs also sought to remove certain individuals from the TMPA camp. The General Manager of TMPA was forced to resign just prior to the settlement of the lawsuit. The turnover in City Managers' Offices and in the upper levels of the city-owned utilities of TMPA members has been nearly 100 percent, with most of the turnover occurring within six months of the settlement of the lawsuits.

Two other lawsuits have questioned TMPA's constitutionality and the validity of its contracts with member cities. Relatively, these suits have been less serious and appear likely to be resolved in TMPA's favor.

TMPA seems to be enjoying a calm in the litigation storm. In fact, the Agency actually has a future power plant site selected at Gibbons Creek, for which much of the litigation has already been won. The Grimes County lawsuit settlement described above included agreement on terms for an arbitrated settlement of issues in the event TMPA proceeds, as is likely, with the construction of Gibbons Creek Unit No. 2, its second 400 MW lignite-fired stem electric generating station.

5.0 TMPA PROJECTS

5.1 Current Projects

5.1.1 Gibbons Creek Unit No. 1

TMPA's first generating project, Gibbons Creek Unit No. 1 is located in Grimes County, Texas. It was 10 percent complete as of January 1, 1980. The 400 MW lignite-fired unit is scheduled to deliver steam generated electricity at commercial levels by mid-1982. The project includes an adjacent surface mine, cooling reservoir and related facilities. (See Figure II).

5.1.2 Comanche Peak Steam Electric Station

On January 2, 1979, TMPA executed a Joint Ownership Agreement to acquire a 6.2 percent undivided ownership interest in the Comanche Peak Steam Electric Station consisting of two 1,150 MW nuclear-fueled pressurized water reactor steam electric units together with associated nuclear fuel, switchyard, sub-station, railroad spur and reservoir and an interest in a certain associated transmission line.

Under the terms of the Agreement, TMPA is obligated to pay 6.2 percent of all future (i) construction costs, (ii) nuclear fuel costs, (iii) operating costs (after the station is placed into commercial operation), (iv) a management fee of five percent of its pro rata share of operating costs and (v) a management fee of percent of its pro rata share of fuel cost (subject to certain cost escalation limitations). Subject to certain operational exceptions, TMPA is entitled to receive 6.2 percent of the net power output that the station is capable of producing at any given time.

TMPA acquired its interest in Comanche Peak from Dallas Power and Light. The undivided ownership interests in Comanche Peak are as follows:

Dallas Power & Light Co.	23 1/3 Percent
Texas Power & Light Co.	28 9/10 Percent
Texas Electric Service Co.	33 1/3 Percent
TMPA	6 1/5 Percent
Texas-Louisiana Power Cooperative	4 1/3 Percent
Brazos	3 1/3 Percent
	100 Percent

In January 1980, Comanche Peak was 66.2 percent complete, with Unit No. 1 standing 77.3 percent and Unit No. 2 standing at 41 percent completion. Commercial operation should be realized in 1981 for Unit No. 1 and 1983 for Unit No. 2.

5.1.3 Transmission Facilities

In 1979 TMPA was successful in negotiating for the transmission of electric power through existing facilities to link the Gibbons Creek and Comanche Peak generating stations. The use of existing facilities for interconnection has decreased TMPA projected capital expenditures by $200 million.

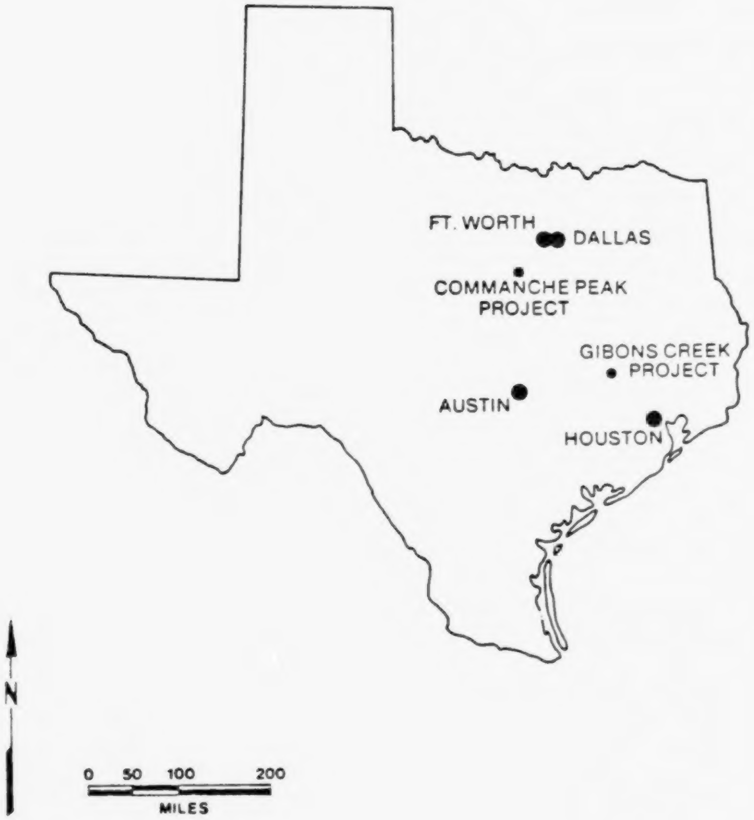
FT. WORTH
DALLAS
COMMANCHE PEAK
PROJECT
GIBONS CREEK
PROJECT
AUSTIN
HOUSTON
N
0 50 100 200
MILES

Figure 2. TMPA projects.

5.2 Future Prospects

TMPA's next generating project will almost certainly be a second 400 MW unit at the Gibbons Creek Station in Grimes County. The site has the benefit of a settled lawsuit in which almost all affected parties were involved and which provides a formula for settlement relating to the second unit. It benefits from an existing cooling reservoir and mining operation and an enhanced opportunity for regulatory permit approvals. It anticipated that the TMPA Directors will submit Gibbons Creek Unit No. 2 to member sites for formal project approval within the coming year.

TMPA and member city officials were reluctant to specifically discuss future projects other than Gibbons Creek Unit No. 2 which is already a matter of public record.

Those interviewed did indicate that projects utilizing lignite on a scale comparable to Gibbons Creek are distinct possibilities for the future. Joint ventures with IOU's are being examined and are considered somewhat likely. TMPA's financial strength due to its bonding authority and tax exempt status make it an increasingly attractive joint-venture candidate from the IOUs' perspective.

6.0 FAU COMPLIANCE STRATEGY

6.1 Consultant's Preliminary Report

During 1979, Stone & Webster Management Consultants, Inc. was commissioned to conduct a "Load Forecast and Power Supply Study" for TMPA. The Purpose of the study was to investigate long-range generation alternatives and to recommend to TMPA its next specific unit generation commitment. Among the consultants' recommendations were the following:

- o Install a second 400 MW lignite-fired generating unit at the Gibbons Creek site.
- o Maintain maximum fuel flexibilities by assuring the Cities' units can burn either natural gas or fuel oil for extended periods.
- o Analyze all of the available options open to the Cities under the Fuel Use Act and prepare a joint plan which will be beneficial to all.

TMPA has hired Stone & Webster to prepare a full report on "Strategy for Compliance with the Fuel Use Act." The "Preliminary Report" was issued in April 1980. The Preliminary Report contains a description of its "Goal," as follows:

> "The objective of this analysis is to identify the plan currently availalbe to TMPA under the provisions of the FUA that will achieve the current, long-term strategy of TMPA and maximize expected value. The current, long-term strategy of TMPA is assumed to be identified in the December 1979 'TMPA Load Forecast and Power Supply Study.' Expected value will be defined as the difference between system revenue requirements of burning 100 percent oil in all required power plants and having these units operate under selected exemptions allowed by the Act."

6.2 Consultant's Conclusions and Recommendation

Stone & Webster's Preliminary Report contained conclusions as to FUA applicability. Stone & Webster found that although the 24 existing steam and gas turbine generating units within TMPA are subject to prohibitions under the FUA, use of significant amounts of natural gas would be allowed in 21 of the units during the period 1980-1989. Only eight of the 21 units would, however, have to generate electricity during that period in light of new TMPA base load. Table III shows the natural gas unit proportions allowed under the FUA for these 8 plants during the 10-year period.

TABLE III

Unit Name	Natural Gas Proportion, %
Olinger 1	99.5
Olinger 2	98.7
Olinger 3	97.4
Atkins 6	99.0
Dansby 1	98.0
Denton 4	99.3
Denton 5	99.2
Greenville 3	96.5

No unit or system exemptions to burn gas or oil will be required during the 1980-1989 period. Due to statutory prohibitions on natural gas, the eight power plants noted in Table III would have to obtain either unit or system exemptions in order to burn gas after January 1, 1990. The system exemption is available to TMPA due to its timely filing of a "Letter of Intent" to file a complete system compliance option prior to January 1, 1980. The FUA prohibitions regarding oil indicate that none of the 24 generating units would be prohibited from burning any quantity of oil after May 8, 1979. Even the eight units noted above will not have to obtain any type of exemption to burn oil.

Finally, the preliminary report notes that FUA discretionary prohibitions may completely prohibit the burning of gas or oil in any TMPA units. Issuance of a Prohibition Order would, however, be contingent on ERA finding the burning of an alternate fuel is both technically and financially feasible on a unit-by-unit basis.

The Comanche Peak nuclear and Gibbons Creek lignite plants are not prohibited under the FUA.

Within the limitations of the FUA, Stone & Webster analyzed 25 different scenarios by which TMPA could achieve full compliance. The scenarios were compared on the basis of the "Expected Value"--a measure of the savings to be obtained in following a particular scenario when compared to the costs of burning 100 percent oil.

Table IV summarizes and ranks the top 5 of the compliance strategies identified and studied by Stone & Webster.

In its Preliminary Report, Stone & Webster recommends that TMPA file a plan under the system compliance option that would cover those gas/oil-fired generating units owned by the member cities. "This recommendation is based on the finding that Plan 3.1 ranks highest in expected value when compared to the 24 other plans considered."

6.3 The TMPA SCO Problem

The problem, recognized by Stone & Webster in their Preliminary Report, is that TMPA may not qualify under Section 504.2 of the regulations as "any person who owns, controls, rents or leases" the existing power plant units owned by the member Cities and may not, therefore, be eligible as the appropriate entity to have a system compliance option plan approved.

At stake is the ability of the TMPA system to utilize gas at its maximum efficiency through future economic dispatch. Much of the benefit of economic dispatch is already realized by the Cities' operations and a system compliance plan which failed to recognize and provide for the transfer of gas (as contractually permitted by Lone Star) would mean a retreat from natural gas and oil conservation already obtained. As stated in the Stone & Webster Preliminary Report, "...the current SCO gas allowance regulations do not recognize the unique situation of TMPA and the Cities. These regulations, if followed, would force inefficient gas/oil-fired generating units to operate after the more efficient units have used up their allowed gas volumes. Such operation is counter to conservation goals and would increase oil consumption on the TMPA system."

A procedural alternative to the TMPA-filed SCO plan is for each of the member cities to file a separate plan with each plan to contain an interlocking, transfer of gas provision. Each city would request that its individual gas allowance under its approved SCO plan be transferrable among the Cities consistent with economic dispatch for best utilization. This combination of four plans, though procedurally cumbersome, would accomplish the same result as a TMPA system-wide SCO plan approval.

TABLE IV
PREFERRED STRATEGIES:
ALTERNATIVES FOR COMPLIANCE

PLAN	UNIT/PETITIONER	EXEMPTION	PERIOD	EXPECTED VALUE ($1,000)
3.1	TMPA	SCO*	1990-1999	111,900
5.2	Olinger 3 Olinger 3 City of Garland	Peak-Temporary Retire-Temporary SCO	1990-1994 1995-1999 1990-1999	81,000
3.3	City of Garland City of Bryan	SCO SCO	1990-1999 1990-1999	78,000
3.4	City of Garland City of Bryan City of Greenville	SCO SCO SCO	1990-1999 1990-1999 1990-1999	74,000
1.3	Olinger 3 Olinger 3	Peak-Temporary Retire-Temporary	1990-1994 1990-1994	72,200

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* SCO = System Compliance Option under Title V of the FUA.

If all attempts at transfer of gas among the member cities fail within the SCO, Stone & Webster nonetheless recommend in their Preliminary Report that each city file its own SCO plan: "In this case SCO gas allowances could not be transferred to the most efficient units in the system. The recommendations; however, this system exemption recommendation would still be preferred to any combination of unit exemptions available under the FUA."

7.0 CONCLUSION

TMPA was not created to facilitate compliance with the FUA. It was created in 1975 in response to the rising costs of oil and natural gas and the perceived needs of its member cities to participate in large scale generating technologies utilizing alternate fuels. The Texas Railroad Commission's Docket 600, portending the end of natural gas as a boiler fuel in Texas, added to the reasons for TMPA but it was economics, not regulatory compliance, which moved the member cities to take advantage of the enabling legislations.

Nonetheless, FUA compliance by the member cities will be substantially eased by their participation in TMPA. Actions taken in their economic interest casued them to anticipate FUA regulatory requirements by decreasing their dependence on natural gas and oil. While many small utilities struggle to understand the FUA and search for a way to comply with its provisions, TMPA consultants have completed their Preliminary Report on FUA Compliance Strategies, identifying at least 25 different scenarios open to TMPA members for compliance with the law. The scenarios have been analyzed to estimate their relative economic value and feasibility. TMPA members are in a position to make informed choices regarding their future and to make those choices based on an extremely favorable situation for compliance with the law.

If the system compliance option regulatory problem, discussed in the preceding section, can be resolved to provide for continued transfer of gas and full economic dispatch between the member cities, TMPA members may be in the position of having to make no substantive changes in their operating plans to achieve FUA compliance. As one interviewee expressed it, TMPA members may be in a position to say, "Here's what we were going to do if the FUA hadn't even come along."

TMPA enabling legislation left open the possibility of additional joint agencies forming in Texas. One such agency has been created. The Sam Rayburn Municipal Power Agency (SRMPA) was created by the Cities of Jasper, Livingston and Liberty in October 1979. These East Texas cities are presently negotiating with Gulf States Utilities for a 20 percent share of the 540 MW Nelson 6 unit in Louisiana. SRMPA members obtained an amendment to the TMPA enabling legislation to provide for their participation in an interstate joint venture.

Additional joint agencies in Texas are possible but not likely in the near-term. Cities of Brownsville and Lubbock have at times expressed an interest, but suffer the problems of geographic isolation. In time, resolution of the legal questions with regard to the interconnection of major Texas utilities across state lines may improve opportunities for wheeling and reduce geographic isolation as a negative factor. TMPA may open its doors at some future point to additional member cities. TMPA may also undertake new joint venture projects with municipal utilities, investor-owned utilities or coops on a case-by-case basis. Either of these options may be more realistic than the formation of separate new agencies in the state.

APPENDIX E

Existing Generating Units Jointly Owned With Small Utilities

Unit/Owners	Fuel	Plant MW	Capacity MW	Share %
Big Stone	Lignite	437		
o Otter Tail Power Company			207.75	47.50
o Northwestern Public Service Company			142.03	32.50
o Montana-Dakota Utilities			87.40	20.0
Bowline 1				
Commonwealth Edison Company	Oil	602	401	67
o Orange and Rockland			201	33
Bowline 2	Oil	600		
Commonwealth Edison Company			400	67
o Orange and Rockland			200	33
Jim Bridger 1	Coal (bit)	500		
Pacific Power and Light			335	67
o Idaho Power Company			165	33
Jim Bridger 2	Coal	500		
Pacific Power and Light			335	67
o Idaho Power Company			165	33
Jim Bridger 3	Coal	500		
Pacific Power and Light			335	67
o Idaho Power Company			165	33
Canal 2	Oil	584		
o Eastern Utilities System Association			292	50
o New England Gas and Electric			292	50
Centralia 1	Coal	650		
Pacific Power and Light			308.75	47.5
o Washington Water Power Company			97.5	8
o Seattle Department of Lighting			52	8
o Snohomish PUD			52	8
o Tacoma Department of Public Utilities			52	8
Puget Sound Power and Light			45.5	7
o Grays Harbor PUD			26	4
Portland General Electric			16.25	2.5

"o" indicates small utility systems.

Unit/Owners	Fuel	Plant MW	Capacity Share MW	Capacity Share %
Centralia 2	Coal	650		
Pacific Power and Light			308.75	47.5
o Washington Water Power Company			97.5	15
o Seattle Department of Lighting			52	8
o Snohomish PUD			52	8
o Tacoma Department of Public Utilities			52	8
Puget Sound Power and Light			45.5	7
o Grays Harbor PUD			26	4
Portland General Electric			16.25	2.5
Coal Creek 1	Lignite	550		
o Cooperative Power Association			222.64	44
o United Power Association			283.36	56
Columbia 1	Coal	556		
Wisconsin Power and Light			242.2	39.3
o Wisconsin Public Service Company			167.0	38.9
Madison Gas and Electric			115.6	21.8
Columbia 2	Coal	556		
Wisconsin Power and Light			242.2	39.3
o Wisconsin Public Service Company			166.7	31.8
Madison Gas and Electric			115.4	22.0
Colstrip 1	Coal	330		
o Montana Power Company			115	50
Puget Sound Power and Light			115	50
Colstrip 2	Coal	330		
o Montana Power Company			115	50
Puget Sound Power and Light			115	50
Conemaugh 1	Coal	936		
Public Service Electric and Gas			191	22.5
Pennsylvania Electric Power			176	20.72
Pennsylvania Power and Light			97	11.39
Baltimore Gas and Electric			90	10.56
General Public Utilities (Metropolitan Edison)			140	16.45
Potomac Electric Company			83	9.72
o Atlantic City Electric			32	3.83
Delmarva Power and Light			32	3.72
o UGI Corporation			9	1.11

Unit/Owners	Fuel	Capacity		
		Plant MW	Share MW	Share %
Conemaugh 2	Coal	936		
Public Service Electric and Gas			191	22.5
Pennsylvania Electric Power			176	20.72
Pennsylvania Power and Light			97	11.39
Baltimore Gas and Electric			90	10.56
General Public Utilities (Metropolitan Edison)			140	16.45
Potomac Edison Company			83	9.72
o Atlantic City Electric			33	3.83
o Delmarva Power and Light			31	3.72
o UGI Corporation			10	1.11
Conemaugh (diesel)	Oil	4-2.8 units		
Public Service Electric and Gas			3.0	22.5
Pennsylvania Electric Power			2.3	20.72
Pennsylvania Power and Light			1.0	11.39
Baltimore Gas and Electric			1	10.56
General Public Utilities (Metropolitan Edison)			2	16.45
Potomac Electric Power			1	9.72
o Atlantic City Electric			0.4	3.83
o Delmarva Power and Light			.4	3.72
o UGI Corporation			.1	1.11
Council Bluffs 3	Coal	650		
o Iowa Power and Light Company			303.55	46.7
o Iowa-Illinois Gas and Electric Company			210.6	32.4
o Iowa Electric Light and Power/Central Iowa and Power Cooperative			50.05	7.7
o Eastern Iowa Light and Power Cooperative			24.70	3.8
o Iowa Public Service Company/Cornbelt Power Cooperative			24.7	3.8
o Cedar Falls			20.1	3.1
o Atlantic			16.25	.5
Craig 2	Coal (bit)	400		
o Colorado-Ute Electric Association			116	29
Salt River Project			116	29
o Tri-State G&T Association, Inc.			96	24
o Platte River Power Authority			72	18
Crystal River 3	UR	890		
Florida Power Corporation			726	90
o City of Gainesville			12	
o New Smyrna Beach Utilities			5	
o Orlando Utilities Commission			13	10
o Sebring Utilities Commission			4	
o Seminole Electric Cooperative			14	
o City of Tallahassee			11	
Edgewater 4	Coal	400		
Wisconsin Power and Light			221.5	68.5
o Wisconsin Public Service Company			103.3	31.5

Unit/Owners	Fuel	Plant MW	Capacity Share MW	Capacity Share %
Fayette Power Plant 1	Coal (sub)	600		
o Austin, Texas			275	50
o Lower Colorado River Authority			275	50
Flint Creek	Coal (sub)	528		
o Southwestern Electric Power Company			264	50
o Arkansas Electric Cooperative			264	50
Four Corners 4	Coal (sub)	800		
Arizona Public Service Company			120	15
Public Service Company of New Mexico			104	13
Salt River Project			80	10
o El Paso Electric Company			56	7
o Tucson Electric Power Company			56	7
Southern California Edison			384	48
Four Corners 5	Coal (sub)	800		
Arizona Public Service Company			120	15
Public Service of New Mexico			104	13
Salt River Project			80	10
o El Paso Electric Company			56	7
o Tucson Electric Power Company			56	7
Southern California Edison			284	48
Hatch 1	UR	850		
Georgia Power				50
Oglethorpe Electric Membership Cooperative				30
o Municipal Electric Authority of Georgia				17.7
o City of Dalton				2.2
Hatch 2	UR	850		
Georgia Power				50
Oglethorpe Electric Membership Cooperative				30
o Municipal Electric Authority of Georgia				17.7
o City of Dalton				2.2
Hayden 2	Coal	262		
o Colorado-Ute Electric Association			52.4	20
Salt River Project			209.6	80
Homer City 1	Coal	620		
o New York State Electric and Gas			309	20
GPU: Pennsylvania Electric Company			310	80
Homer City 2	Coal	620		
o New York State Electric and Gas			309	50
GPU: Pennsylvania Electric Company			310	50

Unit/Owners	Fuel	Capacity		
		Plant MW	Share MW	Share %
Homer City 3	Coal	620		
o New York State Electric and Gas			309	50
GPU: Pennsylvania Electric Company			310	50
Homer City 4	Oil	2		
o New York State Electric and Gas			1	50
GPU: Pennsylvania Electric Company			1	50
Homer City 5	Oil	2		
o New York State Electric and Gas			1	50
GPU: Pennsylvania Electric Company			1	50
Homer City 6	Oil	2		
o New York State Electric and Gas			1	50
GPU: Pennsylvania Electric Company			1	50
Jeffrey Energy Center	Coal (sub)	720		
Kansas Gas and Electric Company			138	20
o Kansas Power and Light Company			435	64
o Missouri Public Service Company			55	8
o Central Telephone and Utilities Company			55	8
Keystone 1	Coal	936		
Public Service Electric and Gas			194	22.84
Pennsylvania Electric Power			179	20.99
Pennsylvania Power and Light			104	12.34
Baltimore Gas and Electric			179	20.99
General Public Utilities (Jersey Central Power and Light)			141	16.67
o Atlantic City Electric			21	2.47
Delmarva Power and Light			31	3.7
Keystone 2	Coal	936		
Public Service Electric and Gas			194	22.84
Pennsylvania Electric Power			178	20.99
Pennsylvania Power and Light			103	12.34
Baltimore Gas and Electric			178	20.99
General Public Utilities (Jersey Central Power and Light)			142	16.67
o Atlantic City Electric			21	2.47
Delmarva Power and Light			32	3.7
Kewaunee 1	UR	560		
Wisconsin Power and Light			212.1	41.0
o Wisconsin Public Service Company			213.1	41.2
Madison Gas and Electric			92.1	17.8

Unit/Owners	Fuel	Plant	Capacity Share	
		MW	MW	%
Keystone (diesel)	Oil	4-2.8 units		
Public Service Electric and Gas			2	22.84
Pennsylvania Electric Power			2.3	20.99
Pennsylvania Power and Light			?	16.67
Baltimore Gas and Electric			2	2.47
General Public Utilities (Jersey Central Power and Light)			2	3.7
o Atlantic City Electric			0.3	
o Delmarva Power and Light			0.4	
Mohave 1	Coal	790		
Southern California Edison			442.4	56
Los Angeles Department of Water and Power			158.0	20
o Nevada Power Company			110.6	14
Salt River Project			79	10
Mohave 2	Coal	790		
Southern California Edison			442.4	56
Los Angeles Department of Water and Power			158.0	20
o Nevada Power Company			110.6	14
Salt River Project			79	10
Navajo 1				
Salt River Project			162.75	21.7
Water and Power Resource Service			182.25	24.3
Los Angeles Department of Water and Power			159	21.2
Arizona Public Service Company			105	14
o Nevada Power Company			84.75	11.3
o Tucson Electric Power Company			56.25	7.5
Navajo 2	Coal (sub)	750		
Salt River Project			162.75	21.7
Water and Power Resource Service			182.25	24.3
Los Angeles Department of Water and Power			159	21.2
Arizona Public Service Company			105	14
o Nevada Power Company			84.75	11.3
o Tucson Electric Power			56.25	7.5
Navajo 3	Coal	750		
Salt River Project			162.75	21.7
Water and Power Resource Service			182.25	24.3
Los Angeles Department of Water and Power			159	21.2
Arizona Public Service Company			105	14
Nevada Power Company			84.75	11.3
o Tucson Electric Power Company			56.25	7.5
Neal 3	Coal	550		
o Iowa-Illinois Gas and Electric			152.25	29
o Iowa Southern Utilities Company			147.00	28
o Iowa Power and Light Company			120.75	23
o Iowa Public Service Company/Cornbelt Power Cooperative			105.00	20

Unit/Owners	Fuel	Capacity		
		Plant MW	Share MW	Share %
Neal 4	Coal	640		
o Iowa Public Service Company/Cornbelt Power Cooperative			295.03	50.87
o Interstate Power Company			100.69	17.36
o Northwest Iowa Power Cooperative			100.69	17.36
o Northwestern Public Service Company			50.34	8.68
o North Iowa Municipal Electric Cooperative			33.25	5.73
Peach Bottom 2	UR	1,152		
Public Service Electric and Gas			448	42.49
Philadelphia Electric Power			449	42.49
o Atlantic City Electric			79	7.51
o Delmarva Power and Light			79	7.51
Peach Bottom 3	UR	1,152		
Public Service Electric and Gas			448	42.49
Philadelphia Electric Power			449	42.49
o Atlantic City Electric			79	7.51
o Delmarva Power and Light			79	7.51
Quad Cities 1	UR	828		
Commonwealth Edison Company			621	75.0
o Iowa-Illinois Gas and Electric Company			207	25.0
Quad Cities 2	UR	828		
Commonwealth Edison Company			621	75.0
o Iowa-Illinois Gas and Electric Company			207	25.0
Roseton 1	Oil	600		
o Central Hudson Gas and Electric			180	20
Commonwealth Edison Company			240	40
Niagara Mohawk				20
Roseton 2	Oil	600		
o Central Hudson Gas and Electric			180	20
Commonwealth Edison Company			240	40
Niagara Mohawk			180	20
Salem 1	UR	1,170		
Public Service Electric and Gas			468	42.59
Philadelphia Electric			460	42.59
o Atlantic City Electric			82	7.41
o Delmarva Power and Light			92	7.41
San Luis 1	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	
San Luis 2	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48

Unit/Owners	Fuel	Capacity		
		Plant MW	Share MW	Share %
San Luis 3	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48
San Luis 4	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48
San Luis 5	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48
San Luis 6	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48
San Luis 7	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48
San Luis 8	Water	53		
o California Department of Water Resources			27.56	52
Mid-Pacific Water and Power Resources			25.44	48
Trojan 1	UR	1,080		
Portland General Electric			729	67.5
o Eugene Water and Electric Board			324	30
Pacific Power and Light			27	2.5
Wansley 1	Coal	952		
Georgia Power Company				53.5
o Oglethorpe Electric Membership Corporation				30
o Municipal Electric Authority of Georgia				15.1
o Dalton, City of				1.4
Wansley 2	Coal	952		
Georgia Power Company				53.5
o Oglethorpe Electric Membership Corporation				30
o Municipal Electric Authority of Georgia				15.1
o Dalton, City of				1.4
Warrick 4	Coal	323		
o Southern Indiana Gas and Electric				50?
Alcoa Generating Corporation				50?
Wyodak 1	Coal	310		
Pacific Power and Light			248	80
o Black Hills Power and Light			62	20
Total		35,081	12,566	

Data Sources:

(1) The 1980 Annual Reports of the nine Regional Reliability Councils: East Central Area Reliability Coordination Agreement, Mid-American Interpool Network, Mid-Atlantic Area Council, Mid-Continent Area Reliability Coordination Agreement, Northeast Power Coordinating Council, Southeastern Electric Reliability Council, Southwest Power Pool, Electric Reliability Council of Texas, and Western Systems Coordinating Council.

(2) Inventory of Powerplants in the United States. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0095(79), December, 1979.

(3) Additions to Generating Capacity 1979-1988 for the Contiguous United States. Economic Regulatory Administration, U.S. Department of Energy. DOE/ERA-0020, October, 1979.

APPENDIX F

FUTURE GENERATING UNITS
JOINTLY OWNED WITH SMALL UTILITIES

Unit/Owners	Fuel	Capacity		
		Plant	Share	
		MW	MW	%
ALEC 1	Lignite	750		
Arkansas Power and Light			450	60
o Arkansas Electric Cooperative			262.5	35
o Jonesboro City Water and Light			37.5	5
Allen 2	Coal	500		
o Nevada Power Company			40	8
Pacific Gas and Electric			368	46
Southern California Edison			368	46
Allen 3	Coal	500		
o Nevada Power Company			40	8
Pacific Gas and Electric			368	46
Southern California Edison			368	46
Allen 4	Coal	500		
o Nevada Power Company			40	8
Pacific Gas and Electric			368	46
Southern California Edison			368	46
Allied 1	Coal	400		
o Iowa Public Service Cooperative/Cornbelt Power Cooperative			100	25
o Eastern Iowa Light and Power Cooperative			50	12.5
o Missouri Basin Municipal Power Authority			50	12.5
o Northwest Iowa Public Cooperative			50	12.5
o Heartland Consumers District Power			30	7.5
o Undetermined			120	30.0
Big Cajun 2, Unit 3	Coal (sub)	540		
o Cajun Electric Power Cooperative				50?
Gulf States Utilities Company				50?
Big Cajun 3, Unit 1	Lignite	540		
o Cajun Electric Power Cooperative			405	75
Gulf States Utilities Company			135	25
Big Cajun 3, Unit 2	Lignite		540	
o Cajun Electric Power Cooperative			405	75
Gulf States Utilities Company			135	25

"o" indicates small utility systems.

Unit/Owners	Fuel	Capacity		
		Plant	Share	
		MW	MW	%
Big Cajun 4, Unit 1	Lignite	540		
o Cajun Electric Power Cooperative			405	75
Gulf States Utilities Company			135	25
Black Fox 1	UR	1,150		
Public Service of Oklahoma			700	59.6
o Associated Electric Cooperative			250	22.4
o Western Farmers Electric Cooperative			200	18.0
Black Fox 2	UR	1,150		
Public Service of Oklahoma			700	61
o Associated Electric Cooperative			250	22
o Western Farmers Cooperative			200	17
Boardman 1	Coal (bit)	530		
Portland General Electric			424	80
o Idaho Power Company			53	10
o Pacific Northwest Generating Company			53	10
California Coal 1	Coal	500		
Southern California Edison			250	50
o Anaheim			15.25	3.05
o Burbank			8.5	1.7
o California Department of Water Resources			44.05	8.81
o Colton			3.35	.67
o Glendale			8.5	1.7
Imperial Irrigation District			11.65	2.33
Los Angeles Department of Water and Power			101.7	20.34
o Nevada Public Power			36.65	7.33
o Riverside			8.5	1.7
o Pasadena			11.85	2.37
Carroll County 1	UR	1,100		
Commonwealth Edison Company			733	67
o Iowa-Illinois Gas and Electric			165	15
o Interstate Power Company			202	18
Clinton 1	UR	950		
Illinois Power Company			760	80
o Soyland Power Cooperative			100	10.5
o Western Illinois Power Cooperative			88	9.5
Clinton 2	UR	950		
Illinois Power Company			760	80
o Soyland Power Cooperative			100	10.5
o Western Illinois Power Cooperative			88	9.5

		Capacity		
Unit/Owners	Fuel	Plant	Share	
		MW	MW	%
Coal Creek 2	Coal	506		
o Cooperative Power Association			222.64	44
o United Power Association			283.36	56
Coal Creek (diesel)	Oil	2.2		
o Cooperative Power Association			1.2	56
o United Power Association			1.0	44
Colstrip 3	Coal	700		
o Montana Power Company			210	27.9
Puget Sound Power and Light			175	23.25
Portland General Electric			140	18.6
o Washington Water and Power Company			105	13.95
Pacific Power and Light			70	9.3
o Basin Electric Power Cooperative			49	7.0
Colstrip 4	Coal	700		
o Montana Power Company			210	27.9
Puget Sound Power and Light			175	23.25
Portland General Electric			140	18.6
o Washington Water and Power Company			105	13.95
Pacific Power and Light			70	9.3
Basin Electric Power Cooperative			40	7.0
Comanche Peak 1	UR	1,150	**	
Texas Power and Light				
Texas Electric Service Company				
Dallas Power and Light				
o Brazos Electric Cooperative				
o Texas Municipal Power Authority				
Comanche Peak 2	UR	1,150	**	
Texas Power and Light				
Texas Electric Service Company				
Dallas Power and Light				
o Brazos Electric Cooperative				
o Texas Municipal Power Authority				
Coyote 1	Coal	410		
o Otter Tail Power Company			143.5	35
o Minnkota Power Cooperative, Inc.			123.0	30
o Montana-Dakota Utilities			82.0	20
o Northwestern Public Service			41.0	10
o Minnesota Power and Light			20.50	5

**Potential owners and their respective shares have not yet been settled.

Unit/Owners	Fuel	Capacity Plant MW	Share MW	Share %
Craig 1	Coal	400		
o Colorado-Ute Electric Association			116	29
Salt River Project			116	29
o Tri-State Generation and Transmission			96	24
o Platte River Authority			72	18
Dakotas Coal 1	Coal	500		
o Minnesota Power and Light			275	55
Northern State Power			175	35
o Otter Tail Power			50	10
Fayette Power Project 2	Coal	550		
o Austin, Texas			275	50
o Lower Colorado Power Authority			275	50
Guthrie County	Coal	650		
o Iowa Electric Light and Power/Central Iowa Power Corporation			400	61.54
o Iowa Southern Utilities Company			150	23.08
o Iowa Power and Light			100	15.38
Hope Creek 1	UR	1,067		
Public Service Electric and Gas			1,014	95
o Atlantic City Electric			53	5
Hope Creek 2	UR	1,067		
Public Service Electric and Gas			1,013	95
o Atlantic City Electric			54	5
Iatan 1	Coal	650		
Kansas City Power and Light			445	70
o St. Joseph Light and Power Company			117	18
o Empire District Electric Company			78	12
Iatan 2	Coal	650		
Kansas City Power and Light			455	70
o St. Joseph Light and Power			117	18
o Empire District Electric Company			78	12
Independence 1	Coal (sub)	740		
Arkansas Power and Light			429.2	58
o Arkansas Electric Power Cooperative			259	35
o Jonesboro City Water and Light			37	5
o Conway			15	2

Unit/Owners	Fuel	Capacity		
		Plant	Share	
		MW	MW	%
Independence 2	Coal (sub)	740		
Arkansas Power and Light			429.2	58
o Arkansas Electric Power Cooperative			259	35
o Jonesboro City Water and Light			37	5
o Conway Corporation			15	2
Intermountain 1	Coal	750		
Los Angeles Department of Water and Power			255.75	34.1
o Anaheim			76.5	10.2
o Burbank			12.75	1.7
o Glendale			12.75	1.7
o Pasadena			25.5	3.4
o Riverdale			51.0	6.8
Intermountain Consumers Power Association			128.25	17.1
Utah Power and Light			187.5	25.0
Intermountain 2	Coal	750		
Los Angeles Department of Water and Power			255.75	34.1
o Anaheim			76.5	10.2
o Burbank			12.75	1.7
o Glendale			12.75	1.7
o Pasadena			25.5	3.4
o Riverdale			51.0	6.8
Intermountain Consumers Power Association			128.25	17.1
Utah Power and Light			187.5	25.0
Intermountain 3	Coal	750		
Los Angeles Department of Water and Power			255.75	34.1
o Anaheim			76.5	10.2
o Burbank			12.75	1.7
o Glendale			12.75	1.7
o Pasadena			25.0	3.4
o Riverdale			51.0	6.8
Intermountain Consumers Power Association			128.25	17.1
Utah Power and Light			187.5	25.0
Intermountain 4	Coal	750		
Los Angeles Department of Water and Power			255.75	34.1
o Anaheim			76.5	10.2
o Burbank			12.75	1.7
o Glendale			12.75	1.7
o Pasadena			25.0	3.4
o Riverdale			51.0	6.8
Intermountain Consumers Power Association			128.25	17.1
Utah Power and Light			187.5	25.0
Jeffrey 2	Coal (sub)	680		
o Kansas Power and Light Company			436	64
o Kansas Gas and Electric			136	20
o Missouri Public Service Company			54	8
o Central Telephone and Utilities Company			54	8

Unit/Owners	Fuel	Capacity		
		Plant	Share	
		MW	MW	%
Jeffrey 3	Coal (sub)	680		
o Kansas Power and Light Company			436	64
o Kansas Gas and Electric			136	20
o Missouri Public Service Company			54	8
o Central Telephone and Utilities Company			54	8
Jeffrey 4	Coal (sub)	680		
o Kansas Power and Light Company			436	64
o Kansas Gas and Electric			136	20
o Missouri Public Service Company			54	8
o Central Telephone and Utilities Company			54	8
Laramie River 1	Coal	500		
o Basin Electric Cooperative			213.5	42.7
o Tri-State Generation and Transmission			120.7	24.13
o Lincoln Electric System			66.7	13.33
o Heartland Consumers Power District			58.4	11.67
o Western Minnesota Municipal Power Agency			38	7.60
o Wyoming Municipal Power Agency			5	1.00
Laramie River 2	Coal	500		
o Basin Electric Cooperative			213.5	42.7
o Tri-State Generation and Transmission			120.7	24.13
o Lincoln Electric System			66.7	13.33
o Heartland Consumers Power District			58.4	11.67
o Western Minnesota Municipal Power Agency			38	7.60
o Wyoming Municipal Power Agency			5	1.00
Laramie River 3	Coal	500		
o Basin Electric Cooperative			213.5	42.7
o Tri-State Generation and Transmission			120.7	24.13
o Lincoln Electric System			66.7	13.33
o Heartland Consumers Power District			58.4	11.67
o Western Minnesota Municipal Power Agency			38	7.60
o Wyoming Municipal Power Agency			5	1.00
Louisa 1	Coal	650		
o Iowa-Illinois Gas and Electric			300	46.20
o Iowa Power and Light			211	32.40
o Iowa Public Service Company/Cornbelt Power Cooperative			100	15.40
o Eastern Iowa Light and Power			30	4.6
o Munis			9	1.4
Marble Hill 1	UR	1,130		
Public Service Company of Indiana			938	83
o Wabash Valley Power Association			192	17

Unit/Owners	Fuel	Capacity		
		Plant MW	Share MW	Share %
Marble Hill 2	UR	1,130		
Public Service Company of Indiana			938	83
o Wabash Valley Power Association			192	17
McIntosh 3	Coal (bit)	334		
o City of Lakeland			200	60
o Orlando Utilities Commission			134	40
Nine Mile Pt. 2	UR	1,080		
Niagara Mohawk Power			443	41
o New York State Electric and Gas			194	18
Long Island Lighting			194	18
o Rochester Gas and Electric			151	14
o Central Hudson Gas and Electric			98	9
Oswego 6	Oil	850		
Niagara Mohawk Power			646	76
o Rochester Gas and Electric			204	24
Ottumwa 1	Coal (bit)	675		
o Iowa Southern Utilities			225	33
o Iowa-Illinois Gas and Electric			125	18.5
o Iowa Public Service Company/Cornbelt Power Cooperative			125	18.5
o Iowa Power and Light			100	15
o Iowa Electric Light and Power/Cornbelt Power Cooperative			100	15
Project 87	Coal	675		
o Dairyland Power Cooperative			520	80
Undetermined			130	20
River Bend 1	UR	940		
Gulf States Utilities			564	60
o Cajun Electric Power Cooperative			282	30
o Sam Rayburn Dam Cooperative			94	10
Rodemacher 2	Coal (bit)	530		
o Central Louisiana Electric Company, Inc.			265	50
o Lafayette Utility Systems			265	50

Unit/Owners	Fuel	Capacity		
		Plant	Share	
		MW	MW	%
Salem 2	UR	1,115		
Public Service Electric and Gas			475	42.59
Philadelphia Electric			474	42.59
o Atlantic City Electric			83	7.4
o Delmarva Power and Light			83	7.4
Salem 3	Oil	48		
Public Service Electric and Gas			20	42.59
Philadelphia Electric			16	42.59
o Atlantic City Electric			4	7.4
o Delmarva Power and Light			4	7.4
Scherer 1	Coal (bit)	818		
Georgia Power Company			192.23	23.5
o Oglethorpe EMC			490.8	60
o Municipal Electric Authority of Georgia			122.7	15.1
o Dalton			11.5	1.4
Scherer 2	Coal (bit)	818		
Georgia Power Company			192.23	23.5
o Oglethorpe EMC			490.8	60
o Municipal Electric Authority of Georgia			122.7	15.1
o Dalton			11.5	1.4
Scherer 3	Coal (bit)	818		
Georgia Power Company			Na	
o Municipal Electric Authority of Georgia			Na	
o Dalton			Na	
Scherer 4	Coal (bit)	818		
Georgia Power Company			Na	
o Municipal Electric Authority of Georgia			Na	
o Dalton			Na	
Sherburne County No. 3	Coal	800		
o Northern States Power			780	97.5
o Lake Superior District Power			20	2.5
South Texas Project 1	UR	1,250		
Houston Lighting and Power			385	30.8
San Antonio City Public Service			350	28.0
Central Power and Light			315	25.2
o Austin, Texas			200	16.0

Unit/Owners	Fuel	Capacity		
		Plant	Share	
		MW	MW	%
South Texas Project 2	UR	1,250		
Houston Lighting and Power			385	30.8
San Antonio City Public Service			350	28.0
Central Power and Light			315	25.2
o Austin, Texas			200	16.0
Southeast 1	Coal	470		
Public Service Company of Colorado			380.2	80.9
o Arkansas River Power Authority			40	8.5
o Uncommitted			42.4	10.6
Southeast 2	Coal	470		
Public Service Company of Colorado			380	80.9
o Arkansas River Power Authority			40	8.5
o Uncommitted			42	10.6
Southwest	Coal	400		
o Colorado-Ute Association			220	55
o Uncommitted			180	45
St. Lucie 2	UR	820		
Florida Power and Light			715	
o Orlando Utilities Commission			49	
o Seminole Electric Cooperative			48	
o Others			8	
Summer #1	UR	900		
o South Carolina Public Service Authority			300	33
South Carolina Electric and Gas			600	67
Susquehanna 1	UR	1,152		
Pennsylvania Power and Light			945	90
o Allegheny Electric Cooperative			105	10
Susquehanna 2	UR	1,152		
Pennsylvania Power and Light			945	90
o Allegheny Electric Cooperative			105	10
Valmy 2	Coal	250		
o Idaho Power Company			125	50
o Sierra Pacific Power			125	50
Vienna 9	Coal	500		
o Atlantic City Electric			125	25
o Delmarva Power and Light			375	75

Unit/Owners	Fuel	Plant MW	Capacity Share MW	Capacity Share %
Vogtle 1	UR	1,150		
Georgia Power and Light			615.25	53.5
o Oglethorpe EMC			345	30.0
o Municipal Electric Authority of Georgia			173.65	15.1
o Dalton			16.1	1.4
Vogtle 2	UR	1,150		
Georgia Power and Light			615.25	53.5
o Oglethorpe EMC			345	30.0
o Municipal Electric Authority of Georgia			173.65	15.1
o Dalton			16.1	1.4
Wansley 5A	Oil			
Georgia Power Company				53.5
o Oglethorpe EMC				30.0
o Municipal Electric Authority of Georgia				15.1
o Dalton				1.4
White Bluff 1	Coal (sub)	740		
Middle South Utilities, Inc./Arkansas Power and Light			429	58
o Arkansas Electric Cooperative Corporation			259	35
o Jonesboro City Water and Light			37	5
o Conway			15	2
White Bluff 2	Coal (sub)	740		
Middle South Utilities, Inc./Arkansas Power and Light			429	58
o Arkansas Electric Cooperative Corporation			259	35
o Jonesboro City Water and Light			37	5
o Conway			15	2
Wolf Creek 1	UR	1,150		
o Kansas Gas and Electric				41.5
o Kansas City Power and Light				41.5
o Kansas Electric Power Cooperative (?)				17.0
o Small Municipals and Utilities				NA
Young 2[a/]	Lignite	408		
o Minnesota Power and Light			204	50
o Minnkota Power Cooperative, Inc.			204	50

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a/ The plant is now operating, but will become a jointly owned facility in 1985.

Unit/Owners	Fuel	Capacity		
		Plant MW	Share MW	%
Miscellaneous				
Coal	Coal	600		
Florida Power and Light			300	
o Sebring Utilities Commission			300	
Fossil/Coal	Coal (bit)			
Florida Power Corporation			600	
o Sebring Utilities Commission			8	
Fossil/Coal	Coal (bit)			
Florida Power Corporation			660	
o Sebring Utilities Commission			8	
Unknown (P)	Coal (bit)	350		
o City of Lakeland			200	
o Orlando Utilities Commission			150	
Total		55,488	24,080	

Data Sources:

(1) The 1980 Annual Reports of the nine Regional Reliability Councils: East Central Area Reliability Coordination Agreement, Mid-American Interpool Network, Mid-Atlantic Area Council, Mid-Continent Area Reliability Coordination Agreement, Northeast Power Coordinating Council, Southeastern Electric Reliability Council, Southwest Power Pool, Electric Reliability Council of Texas, and Western Systems Coordinating Council.

(2) Inventory of Powerplant in the United States. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0095(79). December, 1979.

(3) Additions to Generating Capacity 1979-1988 for the Contiguous United States. Economic Regulatory Administration, U.S. Department of Energy. DOE/ERA-0020. October, 1979.

APPENDIX G

April 17, 1980, Federal Register

Notice and FRA letter to Utilities

DEPARTMENT OF ENERGY

Economic Regulatory Administration

Report to Congress on the Study of Compliance Problems of Small Electric Utility Systems With the Powerplant and Industrial Fuel Use Act of 1978

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Public meeting and request for comments.

SUMMARY: Section 744 of the Powerplant and Industrial Fuel Use Act of 1978 (FUA or the Act) requires the Department of Energy (DOE) to conduct a study of the problems of compliance with the Act experienced by electric utilities with a total system generating capacity of less than 2,000 MW. The study will concentrate on the special difficulties that utilities may face in complying with the FUA prohibitions against the use of natural gas and/or oil, that are a consequence of their small size, and will identify possible technical, regulatory, or legislative remedies.

DOE invites interested persons to provide information, views, and comments and/or to attend a public meeting regarding this study. DOE will consider comments received and make such modifications as appropriate before submitting a final report to Congress. In addition (unless otherwise requested by the commentor), DOE will append to the final report a copy of each set of comments.

DATES: Written comments must be received no later than May 23, 1980. A public meeting will be held on the following date and location: May 15, 1980, Dallas, Texas, Downtown Federal Office Building, Room 7A23, 1100 Commerce Street, Dallas, Texas 75235.

The meeting will commence at 9:30 a.m. local time. Persons wishing to make a presentation are requested to bring six copies of their statement to the meeting location. Persons who notify in advance any of the persons listed below will be scheduled first, followed by others with prepared comments. All persons attending the meeting will then have an opportunity to participate in an informal discussion with the study team.

ADDRESSES: Send written comments to: Small Utilities Study, Office of Utility Systems, Department of Energy, Room 4002, 2000 M Street NW., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT:

Alan W. Starr, Division of Power Supply and Reliability, U.S. Department of Energy, 2000 M Street, NW., Washington, D.C. 20461, (202) 653-3903.

John H. Williams, Division of Power Supply and Reliability, U.S. Department of Energy, 2000 M Street NW., Washington, D.C. 20461, (202) 653-3899.

Lana Ekimoff, Division of Power Supply and Reliability, U.S. Department of Energy, 2000 M Street NW., Washington, D.C. 20461, (202) 653-3899.

Pat Rooney, Office of Fuels Conversion, U.S. Department of Energy, 2000 M Street NW., Washington, D.C. 20461, (202) 254-9795.

SUPPLEMENTARY INFORMATION:

Background

The Powerplant and Industrial Fuel Use Act of 1978 (FUA) prohibits the use of petroleum and natural gas in certain new (generally, any unit which began construction after November 9, 1978) powerplants, prohibits the use of the natural gas in certain existing powerplants after 1990, limits gas consumption by certain powerplants before 1990 to the average yearly proportion of natural gas which such powerplant used as a primary energy source in calendar years 1974–1976, allows the Secretary of Energy to prohibit, by order, the use of petroleum or natural gas, or both, in certain existing powerplants, and restricts the increased use of petroleum by certain existing powerplants unless a permit is issued by the Secretary authorizing such use. Generally, the act covers boilers, combined cycle, and combustion turbine units whose fuel input design capability exceeds 100 million BTU per hour, which corresponds to approximately ten megawatts of electrical output. In some cases, units as small as five megawatts would be covered by the Act.

Section 744 of FUA requires that the Secretary of Energy conduct a study, to be reported to Congress by November 1980, of the problems of small electric utilities (less than 2,000 MW in total system generating capacity) in complying with the act. The study will—

(1) Identify the small utilities likely to have difficulties in complying with FUA.

(2) Perform *case studies* for a representatives sample of utilities, analyzing a variety of compliance strategies.

(3) Estimate the likely contribution of various *technologies* (available now or in the near future) for using coal or alternate fuels on a scale compatible with small utility operations.

(4) Evaluate the *institutional arrangements* that would enable small utilities to share in the use of large scale powerplants (e.g., joint action agencies, joint ownership, generation and transmission cooperatives, or power purchases).

(5) Develop overall conclusions concerning—

(i) The nature and extent of the special problems FUA presents to small utilities.

(ii) Administrative, procedural, or legislative changes to FUA that could alleviate these problems.

(iii) Other Federal or state actions that could improve the ability of small utilities to reduce their dependence on oil and gas.

Request for Information

In order to assure that this study will cover the full range of problems that FUA imposes on small utilities as well as the full range of strategies that small utilities have considered for dealing with these problems, DOE invites comments from small utilities and other interested parties on the following subjects:

(1) Impact of FUA on a specific utility's operating and development plans, and possible strategies for complying with the Act.

(2) Technical and financial feasibility of using coal, either in new boilers or by converting existing boilers, on a scale compatible with the small utility.

(3) Experience (successful and unsuccessful) in using (or considering the use of) unusual alternate fuels such as coal-oil mixtures, lignite, wood urban waste, peat, geothermal, or small hydro, or unusual technoligies such as fluidized bed, gasifiers, compressed air storage, fuel cells, wind or solar.

(4) Attempts to develop local opportunities for cogeneration.

(5) Specific problems involving the process for obtaining exemptions under the Fuel Use Act.

(6) Problems (solved or unsolved) in gaining access to large powerplant projects (for example, via joint action agencies or via part ownership) as well as to needed transmission facilities.

(7) Possible Federal (or State) actions that could help small utilities reduce their dependence on oil and gas. These suggestions should be separated into the following categories:

(i) Changes in FUA administrative procedures.

(ii) Changes in FUA rules.

(iii) Legislative amendments to the Fuel Use Act.

(iv) Other Federal actions, policies, or programs.

(v) State actions, policies, or programs.

Issued in Washington, D.C., on April 11, 1980.

Howard F. Perry,

Acting Assistant Administrator for Utility Systems, Economic Regulatory Administration, (202) 653-[illegible]

[FR Doc. 80-[illegible] Filed 4-16-80; 8:45 am]

BILLING CODE 6450-01-M

Department of Energy
Washington, D.C. 20461

This office is currently preparing a report on the problems small utilities (under 2,000 megawatts) are facing in complying with the Powerplant and Industrial Fuel Use Act of 1978 (FUA). This one-time-only report is required by the Act itself and will be delivered by the Secretary of Energy to Congress by November 9, 1980.

We have tried by various means to assure that the study team is fully aware of the difficulties that small utilities are having with FUA, and to solicit suggestions for alleviating these difficulties by changes either in the regulations or in the Act itself. The enclosed April 17 Federal Register notice described the study, announced a May 15 public meeting, and requested written comments.

We have had discussions with many small utilities as well as with law firms, engineering consultants, and utility trade associations, but we have received very few written comments. We realize that staff and budget limitations make it difficult to keep abreast of all the statutes and regulations affecting the utility business, and we understand that requests for voluntary comments are not likely to be given the highest priority. However, we are concerned that lack of response by small utilities will be interpreted by Congress and by top Administration officials as evidence that no serious problems exist, and that no legislation or regulatory changes are warranted. Furthermore, action to correct any particular problem would be much more likely to occur if the existence of the problem is documented by letters from a large number of utilities.

We believe this study offers a unique opportunity to have your FUA problems addressed by Congress, and that it is in your interest to make your views on this subject known. We are extending the deadline for comments until June 6, 1980, and will accept comments in any format that is convenient for you. If you have any questions, please do not hestitate to contact me (202-653-3903) or the manager of this study, Mr. John H. Williams (202-653-3899).

Sincerely,

Alan W. Starr
Chief, Source Technology and
  Economics Branch
Division of Power Supply and
  Reliability
Economic Regulatory Administration

Enclosure

APPENDIX H

SMALL UTILITY RESPONSES

Lea County Electric Cooperative Inc.

P. O. DRAWER 1447 18 WEST WASHINGTON AVENUE LOVINGTON, N. M. 88260

K. C. MARTIN
Executive Vice President
& General Manager

TELEPHONE
(505) 396-3631

March 24, 1980

Mr. Alan W. Starr
Office of Utility Systems
U. S. Department of Energy
2000 M Street, N.W.
Washington, D. C. 20461

Re: Request for Information - Section 744 of the Fuel Use Act

Dear Mr. Starr:

In response to the above referenced request, we submit the following:

I. Lea County Electric Cooperative, Inc.'s Generating Units:

Type	Fuel	Date Installed
16.5 MW Steam Turbine	Gas/Oil	1962
33.0 MW Steam Turbine	Gas/Oil	1966
20.0 MW Diesel Units	Gas/Oil	1951-1957

II. It is not considered practical to convert the existing units to coal because of the size, age, design, configuration, space, distance to supply and transportation problems.

III. We are considering building a 67 MW gas turbine with a heat recovery boiler to operate with our existing 33 MW unit in a combined cycle system. We made several studies regarding this. This would decrease our heat rate from about 12,300 BTU/KWH to about 9,000 BTU/KWH which would result in a large savings of energy.

We had a pre-application conference in Washington in July of 1979, and have worked on this continuously since then. It appears that at this time our only options remaining are exemptions for 1. peaking purposes, and 2. providing for future synthetic fuel capabilities.

Our studies have shown that adding generation for peaking purposes only would not be economical--especially with the uncertainty of the future price of gas.

Synthetic fuel capabilities also have some uncertainties:
1. do we need to arrange for future sources now;
2. what if it is not available at that time; and
3. what if it is too expensive.

IV. A matter of concern is the possible expense involved with the Fuels Decision Report, especially if required to thoroughly investigate all possible sources of alternate energy.

V. If it is not possible to develop an alternate source of energy, Lea County Electric's use of its generation will be limited and its investment will not be effectively utilized.

Sincerely,

Lea County Electric Cooperative, Inc.

E. R. Felfe

E. R. Felfe
Manager - Production

ERF/cm

cc: Mr. F. F. Stacy
Oglethorpe Power Corporation

NORTH CAROLINA ELECTRIC
MEMBERSHIP CORPORATION

3333 North Boulevard
P.O. Box 27306
Raleigh, North Carolina 27611
Phone (919) 872-0800

March 27, 1980

Mr. Alan W. Starr, Chief
Source Technology and Economics Branch
Department of Energy
Room 4103
2000 M Street, N. W.
Washington DC 20461

Dear Mr. Starr:

I appreciated the opportunity to visit with you briefly while you were attending the NRECA meeting in New Orleans March 2.

As we indicated in our conversation, the electric cooperatives in North Carolina are ready to lead the way in the development of peat as a viable alternative to the continued burning of foreign oil to generate electricity. We are developing a proposal to design and construct a commercial-scale, peat gasification, combined cycle electric generating plant which we believe is compatible with the P.L. 96-126 program.

Present international events should have erased any lingering doubts about the critical need to identify and develop alternative energy sources. Peat fuel represents an enormous energy resource that can be brought to bear in a relatively short time, provided there is sufficient investment. The North Carolina Electric Membership Corporation is seeking a partnership sharing of the front-end risk of this effort.

The first demonstration facility will be costly since it will be the first of a kind in order to hasten the development of this new fuel. It will be in the nation's and the cooperatives' best interest to support facilities that can show immediate results in solving the energy problems and at the same time reduce significant amounts of energy presently produced with imported oil. The risk associated with the development of these facilities utilizing private investment could result in significant delays in utilizing this valuable resource. Therefore, we believe, it is both essential and proper for the federal government to assume a portion of the financial risk for a large scale demonstration facility.

Although the environmental effects of utilizing peat have not been fully established, early evidence is very promising. The overall environmental considerations appear to be favorable.- When the peat is cleared from the land, test plots indicate that it can be utilized as very productive farm land.

Finally, it has been a great disappointment and a puzzle to us that following passage of H.R. 3000 (a bill containing preliminary funding for a demonstration peat-fired electric generating plant) in the House last year and favorable reporting by the Senate Energy and Natural Resources Committee, that DOE would severely restrict our ability to utilize P.L. 96-126 funds for alternate fuel production. In their solicitation notice of February 25 alternate fuels "would not include producing energy from the direct burning of any of the above resources..." (such as peat). For this reason we have decided to evaluate the merits of the peat gasification process, utilizing a combined-cycle generating unit.

Our nation needs this vital energy source. We are ready to share the risk of proving its usefulness to our country. Any support or assistance you and your colleagues can lend to these worthwhile efforts will be most appreciated.

Sincerely,

James M Hubbard

James M. Hubbard
Executive Vice President

JMH/pkg

F.F. "Bud" Stacy
General Manager

2888 Woodcock Boulevard
Atlanta, Georgia 30341
(404) 455-1121

April 1, 1980

Mr. Alan W. Starr
Office of Utility Systems
U. S. Department of Energy
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Starr:

This letter is in response to our March 2, 1980 meeting in the Marriott Hotel in New Orleans, Louisiana. As indicated to you during that meeting, as Chairman of the Technical Advisory Committee of the National G&T Managers Association, I surveyed the G&T Managers to determine problems in compliance with Section 744 of the 1978 Fuel Use Act. Due to the limited time permitted, in complying with your April 1, 1980 deadline, only a few systems were able to respond.

The following briefly summarizes the issues of concern expressed in their response:

A. The major direct problems encountered with the 1978 Fuel Use Act appears to be in the area of interpretation of the regulations.

B. It appears that procedural problems with D.O.E.'s regulations and incentive for use of alternate fuels are mainly with the scheduling. Those systems who are being affected feel that even with an accelerated program, they are questioning their ability to meet the 1990 deadline in the Act.

C. In the area of using innovative technologies with other fuels, many systems have indicated that they have studies underway, but feel there may be some difficulty in the interpretation as to what is alternative fuels. One or two of the systems have expressed interest in coal gasification, wood pulp and methane gas.

Mr. Alan W. Starr
Page Two
April 1, 1980

I regret that I was unable to provide you with more information. The G&T Technical Advisory Committee does have this on their agenda for their April 20, 1980 meeting.

From the responses received from the G&Ts, those systems that are anticipating difficulty in compliance with the 1978 Fuel Use Act have already been in contact with you and expressed their concerns.

Should there be any further information that develops from our April 20 meeting, we will immediately forward it on to you.

If you feel that I can be of any help to you in this endeavor, please do not hesitate to contact me.

Very truly yours,

F.F. Stacy

F. F. Stacy
General Manager

FFS:pp

Burns & McDonnell / Engineers - Architects - Consultants

POST OFFICE BOX 173
KANSAS CITY, MISSOURI 64141

TEL: 816-333-4375 TWX: 910-771-3059
4600 EAST 63rd STREET

April 30, 1980

Economic Regulatory Administration
Case Control Unit (Fuel Use Act)
P.O. Box 4629
Room 2313
2000 M Street N.W.
Washington DC 20461

COPY

Re: Associated Electric Cooperative
Thomas Hill Generating Station - Unit 3
Fuel Use Act
Request for Interpretation on Auxiliary Boilers

Gentlemen:

Burns & McDonnell Engineering Company, Inc. has been retained by Associated Electric Cooperative to provide engineering design and management services to ensure the timely completion and commercial operation of a third unit at Thomas Hill Generating Station in Central Missouri. Unit No. 3, at Thomas Hill, is a 670 MW coal-fired steam electric powerplant. As an integral element of this installation, two auxiliary oil-fired package boilers are required. The purpose of this Request for Interpretation is to solicit a ruling for Associated Electric Cooperative that would include the two auxiliary oil-fired package boilers at the Thomas Hill Generating Station as auxiliary equipment for Unit No. 3.

Unit No. 3 at the Thomas Hill Generating Station is clearly an electric powerplant as defined by Title I, Section 103, (a),(7),(A). This citation states:

> "The terms electric powerplant and powerplant mean any stationary electric generating unit, consisting of a boiler, a gas turbine, or a combined cycle unit, which produces electric power for purposes of sale or exchange and — (i) has the design capability of consuming any fuel (or mixture thereof) at a fuel heat input rate 100 million Btu's per hour or greater; or..."

Unit No. 3, a 670 MW coal-fired powerplant, meets several of these conditions and will be an electric powerplant when commercially operational in mid-January, 1982. Further, it is our opinion, Unit No. 3 is in all likelihood a new electric powerplant. Even though construction began at the site on July 17 1978, and the unit is tentatively a transitional facility, total non-recoverable capital outlays did not exceed 25 percent of the total by November 9, 1978 nor was the boiler at

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this field-erected unit in place by that date. Thus, Burns & McDonnell recognizes that Unit No. 3 would, in all probability, be classified as new should such a request for classification be solicited.

As a new electric powerplant, Unit No. 3 is subject to the general prohibition of Title II of the Act. Title II, Subport A, Sec 201, (1) & (2) state:

> (1) "natural gas or petroleum shall not be used as a primary energy source in any new electric powerplant; and
> (2) no new electric powerplant may be constructed without the capability to use coal or any other alternate fuel as a primary energy source."

Unit No. 3, at the Thomas Hill Generating Station, will use coal as its primary energy source and clearly, when operational, will be in compliance with the aforementioned prohibition. Fuel oil, when used in this unit, will not constitute a primary energy source and will be used solely for start-up and flame stability. Such a use of fuel oil is allowable under the definition of primary energy source as cited on Page 28541 of the May 15, 1979 Federal Register. This reference states:

> "Primary energy source means the fuel or fuels used by an existing or new electric powerplant or major fuel-burning installation, except --
> (1) Minimum amounts of fuel not to exceed 5 percent of the unit's current year output required for unit ignition, startup, testing, flame stabilization and control uses (sic)..."

Thus, the miminum amounts of fuel oil used in the 670 MW coal-fired unit would not be considered as a primary energy source when used at an amount which does not exceed 5 percent of the unit's heat input.

The two oil-fired auxiliary boilers at Unit No. 3 will be used as follows:

1. Main boiler combustion air preheat during start-up of the main boiler unit (and during low load operation if required),
2. Start-up steam for main boiler feed pump turbine driver,
3. Condenser sparging for warmup of condensate during startup, and,
4. Building heat required only when both the main unit and the existing Units 1&2 at the plant are out of service and cannot provide steam flow for building heat.

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The sum of the fuel oil used both in Unit No. 3 startup and in the auxiliary boiler will not exceed 5 percent of Unit No. 3's annual Btu input. Further, the auxiliary boilers and the main boiler are wholly interrelated in that the presence of one necessitates the presence of the other. It is inconceivable that at the Thomas Hill Generating Station, Unit No. 3 would be looked upon as a separate facility from its auxiliary boilers. The reverse is also true.

However, under the Fuel Use Act as we understand it, the auxiliary boilers are not considered as an integral part of the powerplant, but as separate major fuel-burning installations. Title I, Sec 103,(a),(10),(A) states:

> "The term major fuel-burning installation and installation mean a stationary unit consisting of a boiler, gas turbine unit, combined cycle unit, or internal combustion engine which -- (i) has a design capability of consuming any fuel (or mixture therof) at a fuel heat input rate of 100 million Btu's per hour or greater; or..."

Because of this definition, we understand that the two auxiliary boilers for Unit No. 3, which have maximum fuel heat input rates of 158 million Btu's per hour and which were contracted for on November 30, 1978, are classified as new major fuel-burning installation.

It is Burns & McDonnell's considered opinion that such a designation is wholly misleading and inconsistent with the intent of the Fuel Use Act. First, it is misleading to view the auxiliary boilers as separate facilities. Second, it is inconsistent with the intent of the Fuel Use Act to impose burdensome filing requirements to secure allowances, through Title II, Subtitle B, of fuel oil for use in the auxiliary boilers.

We believe these auxiliary boilers should be classified as a part of and not separate from the main boiler because they will be used primarily for unit startup and in combination with fuel oil allowed in the main unit, the total fuel oil heat input will not exceed an annual 5 percent of the main boiler's heat input. We request that such a favorable interpretation be rendered for Unit No. 3 at Associated Electric Cooperative's Thomas Hill Generating Station.

Burns & McDonnell certifies that the undersigned are duly authorized representatives of Associated Electric Cooperative for the purpose of this Request for Interpretation. Your prompt attention to this matter will be greatly appreciated.

Respectfully submitted,

BURNS & McDONNELL
Engineering Company, Inc.

H. L. Wonderly, P.E.
Project Manager
Power Division

WRT
W. R. Thomasset
Section Chief
Planning Department
Planning & Economics Division

HLW/WRT/pmg
cc: Mr. Alan W. Starr, PhD ✓

COPY

NRECA NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
1800 Massachusetts Avenue, N.W.
Washington, D.C. 20036/202-857-9500

May 16, 1980

Dr. John H. Williams
Small Utilities Study
Office of Utility Systems
Department of Energy
Room4002
2000 M Street, N.W.
Washington, D.C. 20461

Dear Dr. Williams:

This letter is to confirm my comments made at the public meeting held in Dallas, Texas on May 15, 1980 concerning Section 744 of the Powerplant and Industrial Fuel Use Act of 1978.

In your discussions with utilities regarding the Section 744 study, many rural electric cooperatives have expressed their beliefs that if they were able to construct the planned nuclear powerplants, that the Fuel Use Act would not be as great a problem to many of them as it presently is.

I would appreciate it if these concerns on the development of nuclear powerplants are included in your November 1980 report to Congress.

Sincerely,

Richard W. Sternberg
Fuels Coordinator

RWS/jh

ROBERT H. BUNTING SECRETARY/TREASURER
WILLIAM G. PARKER PRESIDENT
F. C. LUEDTKE VICE PRESIDENT

The Brazos System

Brazos Electric Power Cooperative, Inc.

JAMES E. MONAHAN
EXECUTIVE VICE PRESIDENT
AND GENERAL MANAGER

May 19, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy Room 4002
2000 M Street, N. W.
Washington, D. C. 20461

Gentlemen:

In response to the Economic Regulatory Administration's request for the comments of small utilities on the Powerplant and Industrial Fuel Use Act of 1978, we have reviewed the anticipated economic and operational impacts of this Act on us, our customers and system and have reviewed our experience with compliance, to date. We appreciate the foresight which the Congress showed in authorizing this study of compliance problems.

BRAZOS GENERATION PLANTS AND FUEL

Brazos Electric Power Cooperative, Inc. is a small electric utility which provides generation and transmission for nineteen member rural electric cooperatives in 55 central and north Texas counties. The member cooperatives whom we serve provide electric service to approximately 135,000 rural homes and customers. Brazos' 490 megawatts of self-generated capacity come solely from power plants which were designed for, and are fired by, natural gas. The system has a limited capability to burn oil. The remaining power requirements come from purchases and from two small, dedicated hydroelectric plants.

Our three newest, and largest, steam electric generating units comprise our R. W. Miller Power Plant and have an average age of 8 years. When the Act's stringent prohibitions become effective in 1990, the average age of these units will be only 18 years, less than half the 40-year useful life. Our North Texas Power Plant units will have an average age of 30 years in 1990. Our third plant, the W. R. (Bob) Poage Plant, is approaching the end of its useful life and is not impacted materially by the Fuel Use Act.

Brazos has taken steps to obtain a diversified system fuel mix. We have contracted for approximately half the capacity of the 400 MW San Miguel Lignite Plant which will go on line in 1981. The Cooperative's initial share of this plant's output is 270 megawatts; the ultimate share is 200 megawatts. We own 87.4 megawatts of the nuclear Comanche Peak Steam Electric Station, divided equally between its two units which will become operational in 1981 and 1983, respectively. Because we are a small utility just beginning to diversify our fuel mix, our natural gas plants will still be important to us for the remainder of the century, and beyond for the Miller Plant. Their use in later years will shift from base load to intermediate load, and later to the less frequently used, but equally important, peaking and backup reserves for emergency and scheduled outages.

If we are unable to use these units,we and our rural customers are faced with the highly uneconomical alternatives of

- converting our plants to coal firing
- decommissioning the natural gas plants well before the end of their useful life and building new plants
- purchasing power from other utilities

There are presently sufficient upward pressures on electric rates to warrant avoidance of other factors which will burden our rural customers.

As the Brazos system grew, using the most economical fuel source, the Cooperative secured long-term fuel contracts to ensure an adequate and reliable power supply for our rural customers. Consequently, Brazos has natural gas contracts with over 85 individual producers to purchase gas at the wellhead, on a take-or-pay basis, such contracts being effective until 1993. Furthermore, this gas is gathered and transported through pipelines which were financed and built specifically to serve our plants. While the Fuel Use Act provides some relief from fuel contractual burdens, it provides none from the investment associated with the pipelines.

The composition of our system was determined by the economics of the time. The prohibitions of the Fuel Use Act present Brazos with an imbalance in the equation of reliability and cost to the ultimate consumer.

COMMENTS ON FUEL USE ACT

Brazos participated in the May 15, 1980 public meeting in Dallas, Texas regarding the impact of the Fuel Use Act on small utilities. In addition to that participation, we wish to offer the following written comments which are directed to ameliorating the economic impact of Fuel Use Act on our ultimate consumers:

> Section 103 (a)(18). We feel that the definitions of "peak load powerplant" and "intermediate load powerplant" are unfairly restrictive on a system with a low load factor, such as ours. Brazos' load factor has averaged slightly less than 50%, with little deviation, for the past 10 years. Our recent load forecast indicates that the load factor will tend to decrease in the future. Therefore, we feel that these definitions should be tied to the system load factor rather than being stated in absolute terms. A limitation on

the use of our plants for intermediate and peaking purposes will have an adverse effect on an economic dispatch operation.

Section 301 (a)(1). We are completely in concurrence with Senator Boren's Bill S-2335 which is attached. This amendment gives full recognition to the needs of a small electric utility which did not have a diversified fuel mix in the mid-1970's. It allows us to make economic decisions on fuel and the composition of our system as we reduce our dependence on natural gas. It also enables us to avoid the onerous petitioning and periodic reporting which are presently integral parts of the Fuel Use Act.

Section 301 (a)(3). In the early and mid-1970's, Brazos periodically used small quantities of oil in its Miller and North Texas plants during gas curtailments and for testing. Since some of that usage occurred during the 1974 through 1976 base period, we are henceforth required to burn some oil to be in compliance with the Act, unless we obtain an exemption. It does not appear to be in the national interest nor in the interest of our consumers to mandate the use of oil particularly when our plants are designed for gas and gas is in ample supply. We feel that this clause of the Fuel Use Act should be modified. In the meantime, we have applied for a temporary Public Interest Exemption for a two year period which our projections indicate to be a period of high, required oil usage. That will leave us with the opportunity to petition another 3 years of temporary Public Interest Exemption from burning oil at a later time.

We would like to emphasize that Brazos, and most electric utilities, have had extreme difficulty in projecting load growth since the Arab oil embargo. That difficulty compounds the development of a strategy on planning when to use the limited durations of exemptions and what exemptions to use. With our small Staff, the problem was complicated. We were unable to reach a satisfactory resolution on the use of the Title V, System Compliance Option, versus the temporary and permanent exemptions to determine which approach minimized the impact on our rural consumers. The opportunity to use Title V expired on January 1, 1980. We comment on this issue under Section 501 (b).

Section 312 (g)(1). The Fuel Use Act does not make provision for a permanent exemption which would allow Brazos to use its Miller Plant units as intermediate load power plants. It refers only to plants subject to prohibitions on the use of petroleum under Section 301. Furthermore, the conditions associated with this exemption are mutually exclusive for a utility which was wholly dependent on gas during the base period specified by the Act. In the various categories of electric utilities, rural electric cooperatives have historically had higher growth rates. This characteristic, and the extensive duration required to gain permits and construct new generation capacity, may leave Brazos needing to purchase power if it cannot have an exemption for intermediate load power plants.

Section 312 (g)(1)(D). The requirement to maintain a net fuel heat input rate (a measure of how efficiently a plant uses its fuel) at or less than 9,500 BTU's per kilowatt hour is not realistic. The August 1979 addition of Electric Light & Power shows only one investor-owned utility fossil-fired boiler, in the entire nation, which bettered this limit in 1978. It also reported that, "Power plant efficiency continued its long-term decline in 1978."

Section 501 (b). For those utilities which have not filed a plan to use Title V, System Compliance Option, we propose that an additional year be made available. The evaluation and studies required for this option are no minor undertaking for a small electric utility.

Section 501 (b)(4). Either of this paragraph's limitations on the use of natural gas is highly restrictive for a utility which was totally dependent on natural gas during the base period. The restriction effectively blocks use of the System Compliance Option.

We understand that our comments will be transcribed verbatem in your report. We appreciate having this opportunity to make them because we are very concerned about the impact of the Fuel Use Act on the rates which our rural customers must bear.

Very truly yours,

James E. Monahan
Executive Vice President
and General Manager

JEM:FMB:lr
Attachment

[illegible]20.246

[illegible]th CONGRESS
Session

S. 2335

IN THE SENATE OF THE UNITED STATES

Mr. Boren introduced the following bill; which was read twice and referred to the Committee on ____________________

A BILL

To amend the Powerplant and Industrial Fuel Use Act to provide extend provisions relating to natural gas.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That section 301 (a) (1) of the Powerplant and Industrial Fuel Use Act of 1978 is amended by inserting ''unless such powerplant used natural gas as a primary energy source at any time during calendar year 1977'' after ''January 1, 1990''.

McDERMOTT, WILL & EMERY
SUITE 1201
1101 CONNECTICUT AVENUE, N. W.
WASHINGTON, D. C. 20036
202-223-9450
TELECOPIER 202-223-0335

111 WEST MONROE STREET
CHICAGO, ILLINOIS 60603
312-372-2000

700 BRICKELL AVENUE
MIAMI, FLORIDA 33131
305-358-6030

FRANK E. BABB
CHARLES EMMET LUCEY
ROBERT F. SAGLE
THOMAS G. MAYS*
RAYMOND D. COTTON
WILLIAM A. CERILLO
D. JANE DRENNAN
JOHN C. TALBOTT
GARY L. RYAN
LAWSON W. TURNER, III*
MICHAEL A. ROMANSKY
DOUGLAS F. JOHN
*Admitted in Virginia only

May 23, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street, N.W.
Washington, D.C. 20461

Gentlemen:

RE: Section 744, Powerplant and Industrial Fuel Use Act of 1978

By notice of April 11, 1980 [45 Fed. Reg. 26119, April 17, 1980], the Economic Regulatory Administration, through the Acting Assistant Administrator for Utility Systems, announced plans to conduct the study required by section 744 of the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA). The purpose of this study is to identify problems which small generating utilities (having installed capacity of 2,000 megawatts or MW or less) are likely to have in complying with the requirements of that Act. Comments were requested to be filed on or before April 23, 1980. South Texas Electric Cooperative, Inc. and Medina Electric Cooperative, Inc. (hereinafter jointly referred to as STEC/MEC, through their undersigned counsel, submit the following comments in response to ERA's April 11, 1980 notice.

STEC/MEC presently do not anticipate having to endure any significant dislocation in order to comply with the requirements of PIFUA. This belief is squarely predicated, however, on the occurence of certain events peculiar to STEC/MEC. In particular, STEC/MEC expect to begin purchasing sizable quantities of power and energy from two sources in the early 1980's. One of these sources will consist of a pair of federal hydroelectric projects located on the

Rio Grande River. STEC/MEC have entered into a long term contract with the United States government relative to this power output, but, until the powerplants have been constructed and delivery of power has commenced, there is always the possibility of delay. STEC/MEC's second source of new power will be a large, lignite-fired generating facility known as the San Miguel Project, currently uncer construction in south-central Texas. Here again, STEC/MEC have no reason to believe that the in-service date for this project will slip significantly. However, there is always that possibility.

In view of the danger that unforseen circumstances will cause disruption in the construction schedules of either of these two projects, STEC/MEC are presently unable to state with certainty that they will be able to strictly comply with the oil/gas phase-out requirements of PIFUA. Should circumstances occur which lead STEC/MEC to conclude that they will in fact not be able to so comply, STEC/MEC will notify ERA and request relief as appropriate.

If you have any questions or comments concerning the statements set forth above, please contact the undersigned, or the General Managers of STEC and/or MEC, whose names and addresses are listed below.

Very truly yours,

Douglas F. John

Douglas F. John

McDERMOTT, WILL & EMERY
1101 Connecticut Avenue, N.W.
Suite 1201
Washington, D.C. 20036

ATTORNEY FOR:

South Texas Electric Cooperative, Inc.
and
Medina Electric Cooperative, Inc.

cc: W. S. Robson
General Manager
South Texas Electric
Cooperative, Inc.
Route 6, Building 102
Victoria Regional Airport
Victoria, Texas 77901

Mr. L.E. Gross
General Manager
Medina Electric Cooperative, Inc.
2308 18th Street
Hondo, Texas 78861

WESTERN FARMERS **ELECTRIC COOPERATIVE**
Post Office Box 429 Anadarko, Oklahoma 73005
405-247-3351

June 2, 1980

Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Starr:

This is in reference to your letter of May 22, requesting us to report on any problems that we may be having associated with the Powerplant and Industrial Fuel Use Act of 1978.

Western Farmers currently operates 718 MW of gas-fired generating equipment, approximately 2312 miles of high voltage transmission line and makes electric power and energy available to approximately 165,000 rural consumers. It has under construction a 376 MW coal-fired generating plant that is expected to come on the line in 1982 and is a part owner in the Black Fox Nuclear Plant, which was originally to come on the line with Unit 1 in 1985 and with Unit 2 in 1987. Black Fox has not received a construction work permit which is pending before the Nuclear Regulatory Commission and it has been necessary to revise the expected completion dates to 1987 and 1990, respectively.

Prior to enactment of FUA, we started an orderly expansion plan to move away from sole reliance on natural gas as fuel for our generating plants. The largest problem associated with FUA is that it dictates actions taking place in specific amounts at specific times, and completely ignores any economics associated with the problem. We have had an engineering study prepared evaluating the various plans that might possibly be followed in future development. System compliance plans dictated by the Act are the most expensive plans that we can follow. The Natural Gas Policy Act of 1978, which arbitrarily inflated gas prices, motivates all electric power producers to seek lower priced fuels to produce electricity. This Act alone would accomplish the same purpose as FUA, but it would not be accomplished quite as rapidly as FUA requires, and would result in the consumption of slightly more gas than would be burned under FUA. There follows a table which compares the cost of an orderly transition of gas to other fuels for the twenty-five year period from 1980 through 2004 to system compliance plans, which show the gas required under each plan, the total incremental expenditures required to accomplish each of the plans, the gas that would be saved over the most economical plan, the additional cost to our consumers and the cost to us per MCF of gas saved.

TABLE

Plan	Gas Required MCF	Total Incremental Expenditures Required X $1000	Gas Saved Over Most Economic Plan MCF	Additional Cost Over Most Economical Plan X $1000	Cost per MCF of Gas Saved
Gas Used Most Economically	300,759,656	$17,196,771	---	---	--
System Compliance Plan #1	200,959,412	19,214,810	99,800,240	2,018,039	$20.22
System Compliance Plan #2	183,144,312	19,481,522	117,615,344	2,284,751	19.43
System Compliance Plan #3	158,668,614	19,964,185	142,091,042	2,767,414	19.48

System Compliance Plan #1 - Western follows system compliance plan and is granted maximum use of gas. All use ceases on January 1, 2000, except for 3 combined cycle units which are granted peaking exemptions from 2000 through 2004. Additional coal-fired units are added to replace gas units.

System Compliance Plan #2 - Same as plan #1 except all gas use stops on January 1, 2000.

System Compliance Plan #3 - Western follows System Compliance plan, but only minimum use of gas is permitted after January 1, 1990. Additional coal-fired units are added to replace gas units.

You will note that the saving varies from 99,000,000 MCF to 142,000,000 MCF at a cost to the consumers in Oklahoma varying from 2,000,000,000 to 2,700,000,000 dollars. The dollar figures are based on 1980 dollars. This quantity of gas would be saved at a cost of approximately $20.00 per MCF which would have to be paid by Oklahoma consumers. Certainly this is not economical and may not be in the public interest in view of the small volume involved. Over the period, the yearly saving in gas consumed represents approximately 0.028% of the total volume of gas consumed in the United States.

FUA, requiring specific actions at specific times, makes it incumbent on us to try to accomplish additions of generating equipment to the system in keeping with a series of legislative and governmental regulations over which we have absolutely no control. The environmental considerations, although worthy of accomplishment, are extremely expensive and are very time-consuming when it comes to obtaining permits to build generating plants. The decision to build the Black Fox Nuclear Plant was made in 1973. Seven years have passed and a construction permit has not been issued, and in view of Three Mile Island, it is anybody's guess as to when it will be issued. With a completion date extended to 1987, over 14 years will have elapsed since the project was originated. Obviously, this forecloses any future consideration of other nuclear plants to replace gas. Our coal-fired plant, which is now under construction, commenced in 1976 and is scheduled to go on the line in 1982. A coal-fired plant starting today would probably take 8 to 10 years from origination to completion in view of all the regulations that must be satisfied. With Black Fox being in a state of suspension, we cannot substitute other planned generation for it, for financing and other reasons. FUA does not take these items into consideration except under the veiled possibility of obtaining emergency gas.

FUA imposes additional restrictions on utilities that elect to accept the system compliance option in that it must have all of its gas purchase contracts dated after November 9, 1978 approved by ERA. We are unable to fathom the rationale of that provision, but we know it would be difficult, if not impossible, to purchase any more natural gas if the competitors in the area where we are buying gas are not required to have their gas contracts approved by ERA. When a gas well is drilled, the producer wants to sell the gas immediately and would probably be very reluctant to commit to a purchaser who requires ERA approval with an attendant delay when another purchaser was standing by that did not require such approval.

It is our recommendation that FUA be repealed, or as an alternative, ERA should be empowered to grant the unlimited use of gas for the existing facilities of those small utilities who, by their actions and plans, are making a move away from the use of natural gas. The additional consumption of gas would not be great and at the same time it would not impose any undue additional financial burden on the consumers of such small utilities.

There is also for consideration the thought that FUA, if it accomplishes its purpose as fully intended, will completely kill the gas industry, that is, from a production standpoint. The economics of gas production has been tied to industrial use, including power plants with the ability to provide a relative uniform market throughout the year. If industrial use is eliminated, residential consumers with high seasonal usage would not provide a marketing base to support the gas industry except at a very high cost.

Other Federal Statutes and regulations that are impeding the transition from gas to other fuels include (1) the amendments to the Clean Air Act which require scrubbers on all future generating plants regardless of the sulphur content of the coal being burned, (2) power plant permitting requirements which are only accomplished after the completion of a very expensive and time consuming Environmental Impact Analysis that is subject to review by countless Federal and State agencies, any one of whom can exercise veto or delaying action on the plan and (3) the general air of negativeness that seems to permeate any actions that are attempted by electric power producers to increase or extend the benefits of electric power and energy to contribute toward maintaining the nation's life style.

Very truly yours,

Maynard Human
General Manager

Enc: Burns & McDonnell
Engineering Study

Sunflower Electric Cooperative INC.

P. O. Box 980 Hays State Bank Building [illegible] Hays, Kansas 67601 (913) 628-2845

June 3, 1980

Small Utilities Study
Office Of Utility Systems
Department of Energy
Room 4002
2000 M. Street N. W.
Washington, D. C. 20461

RE: Fuels Use Act

Dear Mr. Starr:

In your correspondence dated May 22, 1980, you requested comments on problems facing small utilities in complying with the Powerplant and Industrial Fuel Use Act of 1978. Following are some comments on specific problems faced by Sunflower Electric in complying with the FUA:

(1) A utilities allocation of gas for future years use is based upon the utilities historic use of gas in the base years. A large amount of power sold by Sunflower during the base period was purchased power. Therefore, we did not burn much gas in relation to our sales of electrical power. Since we now generate the majority of our power through powerplants utilizing natural gas the percentage of gas used to power sold has increased substantially. However, present usage of gas will not be considered in establishing our allocation because we are no longer in the base period. I believe that this places an unfair burden on Sunflower. I believe some type of adjustment should be accorded utilities that had a high proportion of purchased power during the base period.

(2) We have a 50 MW peaking turbine that was not operational prior to May 15, 1979. Through petition the turbine was classified as existing. If we do not receive an exemption for the turbine we will have to use the system compliance method to receive a gas allocation for the turbine. The problem with utilizing the system compliance method is that the unit would have to be retired in 2004, thereby decreasing its useful life approximately 11 years.

(3) Sunflower has under contract approximately 130 natural gas wells in western Kansas. We have expended considerable amounts of money laying gathering and transmission pipelines whose use will be restricted through use of the arbitraily selected 250 million BTU figure on natural gas production. I believe any user produced gas should be exempted from the FUA.

The above are some of the specifc problems SEC will face in complying with the FUA. More general problems are the financing requirements and early retirements of able units. Hopefully, some adjustments will be made to the FUA thereby relieving the consumer of eventually financing a utilities compliance costs.

Please advise if you require any additional information.

Sincerely,

G. F. Bieker
Gas Operations

GFB:jg

South Mississippi
Electric Power Association
HIGHWAY 49 NORTH
P. O. BOX 1589
HATTIESBURG, MISSISSIPPI 39401

TELEPHONE 544-7131
AREA CODE 601

June 4, 1980

DEPARTMENT OF ENERGY
Division of Power Supply
and Reliability
2000 M Street, N.W.
Washington, D.C. 20461

ATTENTION: Mr. Alan W. Starr

SUBJECT: Compliance Problems with the Fuel Use Act

Gentlemen:

In the South Mississippi Electric Power Association system, the Moselle Generating Plant, which has three (3) units rated at 59 MW each, falls under the provisions of the Powerplant and Industrial Fuel Use Act of 1978 (FUA) as an "existing" powerplant. The plant is ten years old and was originally designed for firing with natural gas but was modified to also burn No. 6 fuel oil in 1974.

Thus far, the problems of complying with the act have been minimized since the plant qualified for a Temporary Public Interest Exemption which permits the continued burning of natural gas for a limited period of time. In addition, with the startup (1978) of SMEPA's 360 MW coal-fired powerplant, the loading on the Moselle unit has been minimized to take advantage of the lower fuel cost afforded by the coal-fired plant. At this time, Plant Moselle is operated primarily as a peaking station.

Except for the existence of these particular elements, SMEPA would be extremely hard pressed to comply with the provisions of the act. Without further future exemptions or other revisions which offer relief for the older, less used, such units, SMEPA will face tremendous financial and technical challenges in converting to an "alternate" fuel such as coal. Coal transportation facilities are non-existent presently; there is no barging option; the plant is too remote for trucking; and the nearest railroad is about three miles from the plant with an interstate highway located in between. The actual site limitations would further complicate conversion due to the minimum amount of property available for expansion which would be essential for the additional coal handling and environmental control equipment.

As a pracical matter, it is technically and economically unreasonable to convert natural gas fired generating units to coal. Such a conversion would essentially require the replacement of the plant. The entire boiler would have to be replaced, rail lines, additional real estate, and extremely expensive environmental control equipment would be required to enable burning of coal.

Some relief in the act is essential which would permit these older and smaller plants to continue operation while burning fuel oil and natural gas as may be required to serve the respective system generation demands. The economics involved in the purchase of the fuel will be incentive enough to conserve gas and oil to the greatest extent possible while taking advantage of coal, hydro, and nuclear generation and the lower associated fuel cost. High cost fuel can only be justified for use in a lower unit cost plant, operating at low capacity factors. SMEPA, as well as other utilities, minimize the dispatch of high cost fuel generation in favor of lower incremental costs of coal, hydro, and nuclear generation. The FUA disregards these principles and requires that oil and gas burning facilities be compared to alternate fuels such as nuclear and coal at a fixed high plant operating factors.

In another area of impact, the FUA has greatly increased the reporting requirements and thus the SMEPA staff efforts have expanded to assure compliance.

The intent of the FUA in discouraging expanded use of oil and natural gas s commendable. Unfortunately, the act does not promote reasonable and practical alternatives for utilities with older units to follow. In ctuality, the act ignores the fact that the extra cost of conversion may xceed the social benefits which may be realized from reduced reliance on etroleum imports.

MEPA previously expressed an interest in participating in a test program romoted by the Department of Energy involving the burning of a coal/oil ixture in plants which were utilizing No. 6 fuel oil. Upon learning hat the Moselle units were designed originally for burning natural gas, MEPA was advised that the Moselle Plant was not eligible for further onsideration.

MEPA is in the process of purchasing an interest in a nuclear generating tation which is under construction in Mississippi. However, system lanning has been and continues to be critically complicated due to the ncertainties brought about by construction delays and licensing problems ssociated with the project.

n the event that the act is not revised to provide further exemptions or ther relief especially for small utilities with limited backup generation and resources, SMEPA will likely face serious problems in both achieving compliance and in serving its system generation requirements adequately in the years to come.

Very truly yours,

George B. Taylor

George B. Taylor
General Manager

GBT:nj

cc: Mr. Dick Sternberg
Mr. Marcus Ware

united power association

elk river, minnesota 55330 • phone 612-441-3121

June 13, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Starr:

Subject: Shredded Tires as a Supplemental Boiler Fuel at Elk River Station

This is in response to your request for a summary of our experience with burning tires included in your letter of May 22, 1980 to Mr. Philip O. Martin.

Elk River Station Units 1 and 2 are essentially identical units rated at 11,500 kilowatts each. The boilers serving the turbine generators are each stoker-fired, Springfield boilers designed to burn coal, #2 fuel oil, #6 fuel oil or natural gas. The primary fuel presently used for these boilers is raw unwashed coal delivered directly from the mine. Each boiler is rated at 135,000 lbs. per hour of steam. The fly ash is collected from the flue gas in a Research Cottrell Model No. 324-12,264, Series 8 baghouse. This baghouse serves all three units at Elk River Station.

The tests on burning a mixture of coal and rubber tire chips or shredded rubber tires have proven the feasibility of such an approach for these two units. Initial tests were conducted in June, 1979 burning a mixture of 5 percent chipped rubber tires and 95 percent western coal and a second test burning 10 percent chipped rubber tires and 90 percent western coal.

Observations of the boiler operation were as follows:

A. The short term tests did not result in any malfunction of boilers because of adding rubber chips to the coal.

B. Soot blowoff and pulling of bottom ashes from the boiler were normal during all rubber chip burning tests.

C. The tests show no increased danger of boiler corrosion for up to 10 percent rubber tire chips/coal mixture.

D. The amount of fine carbon black aerosol generated by burning rubber tire chips increased with increasing rubber chip content in the fuel.

The following observations were noted for the fly ash control system:

A. The baghouse operated properly and maintained a very high collection efficiency throughout the tests.

B. Particulate emissions were well in compliance with existing mass emission and visible emission regulations for all test runs.

C. The presence of carbon black particles from burning rubber chips increased the rate of baghouse pressure drop rise. As a result the baghouse may require more frequent cleaning for continuous burning of rubber chips.

D. When cyclone fly ash collectors are used to control the boiler air emissions, the maximum allowable content of rubber chips will be limited by the 20 percent opacity regulation on visible stack emissions.

Further tests using a mixture of 10 percent shredded rubber tires and 90 percent western coal were conducted in 1980. No detrimental effects were noted in the operation of these two units. It is our plan to continue burning a mixture of shredded tires and coal in Units 1 and 2 in Elk River. This plant is used primarily for peaking service and during maintenance outages of other units on the system. The amount of generation expected on these units will be quite small. It is anticipated that between 1,000 and 2,500 tons of shredded tires can be burned in a year.

If you wish additional information on the test burn and subsequent experience, please let us know.

Sincerely yours,

UNITED POWER ASSOCIATION

Reynold S. Rahko, Manager
Projects Coordinating Division
RSR:mn
cc: P. Martin
D. Kettner

ORRVILLE MUNICIPAL UTILITIES

Electric, Water and Waste Treatment Systems

MUNICIPAL BUILDING • P. O. BOX 126 • ORRVILLE, OHIO 44667 • TELEPHONE 216/682-4976

ROBERT A. NICHOLS, *Director of Utilities*

April 1, 1980

U. S. Dept. of Energy
Office of Utility Systems
2000 M St. N.W.
Washington, D.C. 20461

Attn: Mr. Allen W. Starr

Subject: Fuel Use Act

Gentlemen:

We understand you are seeking comments from small electric utilities re problems we face in meeting the prohibitions of the Act.

Our problems and those of similar utilities are many and varied. Frankly, our main problems are obtaining, studying and understanding the Fuel Use Act, or any other act.

Most of us do not have the manpower or expertise that is required to properly address any new regulations.

The City of Orrville owns and operates its own electrical generation and distribution facilities. We were an isolated utility until the last quarter of 1978. Our electric administrative and supervisory staff consists of a Director who is responsible for three utilities - Electric, Water & Wastewater (myself); a Manager of Electric Utility, a power plant supt. and a distribution supt. Even if they had some free time, their expertise re interpreting government regulations is, at best, below requirements. In addition, we normally do not receive copies of regulations until they are already in effect and, with so many new and changing regulations we have to depend on our trade associations and other contacts to alert us when something is proposed that will adversley affect us.

We have two (2), nominal 25MW, pulverized coal fired units which can and have burned fuel oil and both of which have natural gas ignites. Because of the substantial cost difference between coal and fuel oil, we only burn fuel oil in emergencies. We hope and trust the new act does not prohibit these uses. If so, our customers could be in serious trouble at some future time.

Also, we are concerned about future generations. We must be allowed to install peak shaving and emergency back-up at some future date. Hopefully, obtaining the necessary permits will not be too involved. If the procedures are difficult, we will have to retain consultants to do the work for us and, based on past experience, these consultants are expensive. We cannot afford much more.

It may be necessary to remind you that we are a non-profit organization and we (Orrville) can prove it.

If you wish further input from us, we will do our best to accommodate you.

Yours truly,

Robert A. Nichols
Director of Utilities

ds

cc: APPA
OMEA

City of Lakeland
WORLD CITRUS CENTER
LAKELAND, FLORIDA 33802

DEPARTMENT OF ELECTRIC AND WATER UTILITIES
OPERATIONS CENTER · TELEPHONE 813-682-1121

P.O. BOX 368
1000 EAST PARKER STREET

R. G. SIEGEL, P.E.
ASSISTANT DIRECTOR

May 6, 1980

Mr. Alan W. Starr - Chief
Source Technology and Economics Branch
Division of Power Supply
U. S. Department of Energy
2000 M. Street N. W.
Washington, D. C. 20461

Dear Alan:

It was a pleasure talking with you last Wednesday regarding the City of Lakeland's present and future fuel use plans. Mayor Oldham, Gene Chao, Dennis Gallant and I greatly appreciate Ms. Ekimoff's and your time and attention.

As I mentioned we would still submit our comments to your questionnaire in writing and they are enclosed with this letter.

Thank you again for the opportunity to discuss our fuel situation.

Very truly yours,

R. G. Siegel, Assistant Director
Department of Electric & Water Utilities

RGS/vb

cc: W. R. Lesnett
D. K. Smith

RESPONSE TO REQUEST FOR INFORMATION
BY THE CITY OF LAKELAND
TO THE DEPARTMENT OF ENERGY - ERA
PROBLEMS OF COMPLIANCE WITH FUEL USE ACT OF 1978

1. Subject - Impact of FUA on a specific utility's operating and development plans, and possible strategies for complying with the act.

   Comments - The City of Lakeland has historically used residual oil as their base energy source. Natural gas has been available as an alternate fuel up to 75% of total energy requirements. Since 1973 when oil prices quadrupled, natural gas has played a key roll in keeping electric energy costs to our customers within reasonable limits, due to its much lower price.

   The City of Lakeland recognizes and agrees with the national goal of reducing oil imports and conserving non renewable energy resources. The City must, however, recognize and mitigate if possible severe economic penalties to our customers due to high fuel costs. We have made a commitment to reduce dependence on fuel oil and natural gas by constructing all new generation to be fueled with coal and municipal refuse.

   In addition, we have requested a grant from the D.O.E. to develop coal-oil mixture technology for use in existing generating units. These major projects take time to implement, however, and in the interin period, natural gas is vital to holding electric energy costs in control.

2. Subject - Technical and Financial Feasibility of using coal, either in new boilers or by converting existing boilers on a scale compatible with the small utility (< 2000 MW).

Comment - It is presently technically and financially unfeasible to convert our existing oil/gas boilers to coal. We are specifying coal for future units. It should be noted, however, that excessive rail transportation rates due to deregulation and sole source transportation supplier could make coal financially unfeasible in the future. All efforts possible should be made to assure reasonable competitive transportation rates.

Coal slurry pipelines should be supported as alternate transportation methods - all rates should be subject to I.C.C. review and audits.

3. Subject - Experience (successful or unsuccessful) in using (or considering the use of) unusual alternate fuels such as coal-oil mixtures, lignite, wood, urban waste, peat, geothermal or small hydro, or unusual technologies such as fluidized bed, gasifiers, compressed air storage, fuel cells, wind or solar.

Comment - We presently do not have any experience with the above technologies, we are however:

A. Planning for use of municipal wastes, up to 10% of energy required in our McIntosh Plant Unit 3 (364MW) presently under construction.

B. Planning a retrofit demonstration of the use of coal-oil mixtures in our existing McItnosh Plant Unit 2 (115MW).

C. Planning test installations of solar hot water heating.

D. Have in service heat pumps for demonstration purposes.

E. Planning installation on air condition/heat pump energy recovery units for hot water heating.

4. Subject - Attempts to develop local opportunityies for cogeneration.

Comment- The City of Lakeland is developing a rate schedule for cogeneration as required by PURPA. We have identified existing customers with possible cogeneration potential and plan to discuss cogeneration opportunities with them.

5. Specific problems involving the process for obtaining exemptions under fuel use act.

Comment - We presently have an exemption for nine of our existing generating units. There did not appear to be specific problems in the process. However, serious problems occurred in the application of the exemption as interpreted by D.O.E. requiring major efforts on the part of many people to finally result in an exemption which we could use.

6. Problems (solved or unsolved) in gaining access to large power plant projects (for example, via joint action agencies or via part ownership) as well as needed transmission facilities.

Comment - The City of Lakeland is currently participating in a joint venture plant. We have access to future plant as may be necessary. Transmission facilities have been no problem to date. The lack of problems on our part does not, however, infer that other utilities (particularly small municipals) are not having any and indeed may have serious difficulties in participating in such projects. Within the state, the Florida Municipal Power Authority is addressing these problems.

7. Possible Federal (or state) actions that could help small utilities reduce their dependence on oil and gas. These suggestions should be separated into the following categories:

(i) Changes in FUA Administrative Procedures

(ii) Changes in FUA rules

(iii) Legislative amendments to fuel use act.

(iv) Other federal actions, policies or programs

(v) State actions, policies or programs

Comments

(i) none

(ii) none

(iii) none

(iv) The rigid and inflexible regulations of the clean air act as administered by E. P. A. prevent or impede utilities from reducing oil and gas dependence.

Specifically, our program to demonstrate commercial use of coal-oil mixtures is hampered by inflexibility of new source performance standards and E.P.A. which do not provide for variance in emissions to test new and innovative technologies. The net effect of this policy is to make economic justification of such tests very difficult. This is particularly hard to explain when the plant to be tested is located in a very low SO_2 ambient level area and net emissions from all units at the plant would increase minimally during the demonstration.

It is this type of problem which discourages all utilities from pursuing action to reduce oil and gas dependence.

(v) none

CITY OF BURBANK

164 WEST MAGNOLIA BOULEVARD, P.O. BOX 631
BURBANK, CALIFORNIA 91503

CITY OF BURBANK
INCORPORATED 1911

PUBLIC SERVICE DEPARTMENT

May 15, 1980

Small Utilities Study
Office of Utility-Systems
Department of Energy
Room 4002
2000 M Street NW
Washington, DC 20461

Gentlemen:

Powerplant and Industrial Fuel Use Act of 1978

The City of Burbank Public Service Department owns and operates its own electric generating transmission and distribution system to supply electricity within the boundaries of the City of Burbank.

The Public Service Department presently operates four steam electric generating units with a continuous net capability of 148 MW on oil fuel and three gas turbine-driven electric generating units with a one-hour net capability of 74 MW on oil fuel. Installed generating units are described as follows:

Magnolia Plant

Unit	Type	Net Capability	Installed	Status
No. 1	Steam Turbine	10 MW	1941	Inactive
No. 2	Steam Turbine	10 MW	1943	Inactive
No. 3	Steam Turbine	20 MW	1949	Active
No. 4	Steam Turbine	28 MW	1953	Active
No. 5	Gas Turbine	22 MW*	1969	Active

Olive Plant

Unit	Type	Net Capability	Installed	Status
No. 1	Steam Turbine	42 MW	1959	Active
No. 2	Steam Turbine	58 MW**	1964	Active
No. 3	Gas Turbine	19 MW	1972	Active
No. 4	Gas Turbine	33 MW*	1975	Active

For many years, because of the uncertainty of long-range supply of oil and gas and rapidly escalating costs for these fuels, the City has undertaken to participate in electric generating projects based on other energy resources such as nuclear, geothermal, and coal projects. The Sundesert Nuclear Project in which we were a participant was not approved for construction by the State of California Energy Commission. The Geothermal Energy Development Program in which the City was a participant has been delayed by both excessive environmental regulations and high costs of generating electricity, as well as the inability to gain a reliable transmission path for the energy.

We are currently participating in the development of several coal-fired projects in which we are projecting our share of the capacity as follows:

Project	Location	Capacity	Starting Date
Intermountain Power Project	Utah	47 MW	1989
White Pine Project	Nevada	26 MW	1989
California Coal Project	California	24 MW	1989
AEPCO Coal-Fired Project	Arizona	50-100 MW	1988

Even with these outside energy resources, the City of Burbank will still be dependent on the use of its present gas and oil-fired generating facilities for maintaining reliability in case of outages of transmission lines and for meeting peak demands.

We feel the requirement to convert existing power plants to other sources of fuel by 1990 will be impractical because there is no space available for storing coal and we have no railroad lines into the plant. We are also convinced that the air pollution requirements under which we operate would prohibit the use of coal in generating power in the Los Angeles basin. We have looked at alternative fuel such as methane and burning of solid waste; however, the supply of solid waste, if entirely converted to energy in

Burbank, would supply less than five percent of our needs. We also feel that it is not in the public interest to expend a large amount of money necessary to convert power plants which are over 20 years old and, in our case, even the newest steam turbine, which was installed in 1964, will be 26 years old by 1990. Our newer units, which are gas turbines, are designed to burn either gas or a highly refined distillate fuel in order to comply with air pollution control regulations, and will be contributing less than six percent of our energy needs by 1990. We again feel it would not be prudent to invest large sums of money to convert these units to alternate fuels.

We believe there should be some clearly defined exemptions provided for in order to make it possible for utilities in our situation to continue to operate such facilities in a reliable and economic manner.

James D. Woodburn
Chief Engineer

JDW:j

cc: R. O. Snyder

UTILITY BOARD OF THE CITY OF KEY WEST

POST OFFICE DRAWER 1060

KEY WEST, FLORIDA 33040

May 16, 1980

Small Utilities Study, Office of Utility Systems
Department of Energy
Room 2000 M Street N. W.
Washington, D. C. 20461

RE: Comments on the Study of Compliance Problems of Small Electric Utility Systems with the Power Plant and Industrial Fuel Use Act of 1978, Section 744

Gentlemen:

This report illustrates the problems the City Electric System will have in compliance with the Act, and the difficulties that we face in complying with the F.U.A. prohibitions against the use of oil.

This report provides the most logical cost effective means for reducing our consumption of oil, which is the only energy source used by the CES for electric generation.

The CES is a municipal electric utility with 17,500 customers. It services the City of Key West and the lower Florida Keys to the seven-mile bridge (42 miles). The CES is an island system with no electric tie to any other system.

The CES purchased approximately 775,000 barrels of oil last year and generated 340,000,000 KWH, with a system demand of 64,000 KW. The prime source of generation is six (6) turbine-generator units, the largest being 37 MW, a 22 MW gas-turbine and 13 MW of diesel peaking units (6). The nameplate capacity of the presently installed generation units of the CES total 132,400 KW; dependable capacity is 126,500 KW.

The CES has had very little growth since 1970, due primarily to the military cutback in this area. This has contributed to the area being an economically depressed area. The CES has had cash flow problems because of the high cost of fuel and the area's economical problems. These cash flow problems have limited the CES's ability to performing large capital programs.

This report also refers to the Florida Keys Aqueduct Authority's desalination plant (2.4 million gallons a day). This plant is located next to our Stock Island Steam Turbine Generator (37 MW plant).

The FKAA is a governmental utility responsible for supplying fresh water to the Florida Keys. The Key West area consumes approximately 8 million gallons of water per day, with approximately 1.6 million supplied by the desalination plant. The balance is transported via a pipe line from Homestead, Florida (120 miles north of Key West). The FKAA uses approximately 120,000 barrels of oil annually to make the fresh water. The CES and the FKAA together use approximately 900,000 barrels of oil per year. The use of coal in the CES's boilers to generate electricity is not feasible because of boiler design, transportation and available land.

The following is in answer to procedure as outlined in Federal Register Vol. 45 No. 76, April 17, 1980, Section 744 -

1. The Impact of F.U.A. on the CES operating and development plans and possible strategies for complying with the Act.

The CES is totally dependent on No. 6 oil for it steam generating units and No. 2 oil for it combustion turbine and peaking diesel units. The CES has no electric tie with any other electric system. Without a major capital expenditure, the CES cannot reduce its dependence on oil and comply with the F.U.A.

The CES strategies for complying with the F.U.A. and lowering our dependence on oil are:

(a) Construct a 138 KV transmission line from Key West to the Florida Electric Grid. The CES has the opportunity of joining with our neighbor utility, the Florida Keys Electric Co-op in constructing a 138 KV transmission line through our respective systems. This would enable the CES to purchase 50 MW of power from other power sources in the Southeast, giving us a mixture of energy at lower heat rates than we can generate at.

In a recent study made by our consulting engineers, they said "If Key West could purchase one half of the power requirements from other utilities in Florida at the published rates of whole sale power, the savings to the CES customers would be between 10 and 15% of the present power bill." Based on their information, this would reduce the CES's consumption of fuel by 400,000 barrels annually.

The tie line will greatly increase the reliability of service in Key West through the ability to purchase energy from a mixture of energy sources, and the CES will then be connected to the Florida Grid, giving us greater flexibility and increased continuity of service. The cost to the CES to construct this transmission line is estimated to be $39,700,000.

This tie line development is a single line development of a 138 KV transmission line from the CES's Big Coppitt Key Substation to Florida Power and Light Company City Substation on mainland Florida, located just below Homestead, Florida, approximately 40 miles of this line is with in the CES service area and 80 miles in the Florida Key Electric service area. The line in the Florida Keys Electric service area will be jointly owned by the CES and FKE.

The CES will be entitled to 50 MW over this line. The FKE is now constructing a portion of this line in their area and they intend to complete the line in their area by 1985. The CES is not participating in the constructing of this line because of economical problems. If the CES does not contract with the FKE soon in the constructing of this line, there is a good possibility that the 50 MW of capacity will not be built into the line. It is impossible for the CES to construct a transmission line to the Florida Grid without joint participation with the FKE.

The balance of the CES loads (over 50 MW) will have to be supplied from its existing generators.

(a) Diesel Generation - To reduce oil consumption and save money for our customers, the installation of slow-speed diesels for generation is a very logical approach for generation. To achieve maximum energy efficiency with minimum fuel consumption, I recommend the installation of three 10 MW slow-speed diesels that have the capacity of burning the heaviest of residual oils. In addition, these engines will be particularly adaptable to the use of coal-derived liquid fuel and potentially a pulverized coal and oil slurry.

In this report, all of the systems are based on heavy residual oil. The engines are a two stroke, corss-head design, incorporating exhaust-driven turbo super charges and an exhaust waste heat recovery system. This heat recovery unit can also be used in connection with a flash evaporator unit to make fresh water, or additional generation.

Using 90% efficiency, the three 10 MW units will generate approximately 236,500 KWH annually, with a heat rate of 8,500 BTUs per KWH and the fuel consumption will be 319,000 barrels. The existing heat rate of the units in our Key West Plant is approximately 14,000 BTUs per KWH, so for the same amount of KWH (236,500,000), it would take 525,600 barrles of fuel. By installing the 30 MW of slow-speed diesels, the CES would save 206,000 barrels of fuel a year. These units could be on line within 30 months after being contracted for, and it would be advisable to constract for these units prior to 1983. The capital cost of installing these diesel units (three-10MW) is estimated to be $950.00 per KWH, or $28,500,000.

(c) Co-Generation - The CES could supply sufficient energy to the FKAA to make 4 to 6 million gallons of fresh water daily. This energy could be derived from the existing steam turbine unit (37 MW) in the form of cooling or low pressure steam. It could also be supplied from diesel generators with heat recovery units. If the energy is extracted from the existing steam turbine generator there will be a small loss in its maximum output. If it comes from the diesels, it would only necessitate the installation of a heat recovery unit being installed when they are purchased.

It will be advisable to purchase new or additional flash evaporator units to convert this quantity of fresh water. There will also be a cost to make the necessary modifications to our boiler, or to install heat recovery units in the diesels. This total cost for the CES and FKAA equipment is roughly estimated at 6 or 7 million dollars to increase the volume of fresh water three times and save 120,000 barrels of oil per year.

(d) Constructing of an OTEC Plant for future fresh water and electric demands in the Lower Keys, we propose the construction of a solar powered desalination/ power generation plant in Key West.

We recommend that a feasibility study be made at this time to establish the technical and estimated cost of such a project.

The most logical system is a "Solar Energy Pond/ Ocean Desalination plant." This is a hybrids thermal energy conversion system which employs solar ponds as the heat source and cool water from the ocean depths (or on shore deep wells) as the heat sink.

This system has widespread application possibilities in our tropical area with access to deep water.

This concept is innovative in its combination of solar pond with cooler sea water heat sink to increase efficiency and cost effectiveness.

This system could eliminate our dependence on all other forms of energy and render economical energy and water to the residences of the lower keys and other areas of Florida.

2. Technical and Financial Feasibility of using coal.

It is not economically feasible to convert our existing boilers from coal to oil because the efficiency in our boilers would drop by approximately 36%, and the conversion from oil to coal will be very expensive.

There is not enough property in the vinicity of our plants to store and handle coal, or its residue.

There is not sufficient property in this area that is suitable for the construction of a new coal fired power plant.

3 Experience in Using Unusual Alternate Fuels; Such as Solar.

In the first section of this report we explained our interest in the construction of an OTEC Plant in our area and our goal is to have a feasibility study preformed to provide the necessary answers and justifying an OTEC project in Key West.

It is our opinion that this feasibility report will show the justification for constructing a pilot plant in Key West where both fresh water and electric power are needed.

4. Attempts to Develop Local Opportunities for Co-Generation.

In the first section of this report we explained how fresh water could be produced from spent energy in our existing 37 MW steam plant on Stock Island. This would save approximately 120,000 barrels of fuel annually. To achieve co-generation it would necessitate the installation of a flash evaporator (or similar equipment) and other related equipment. This would be a combined effort of the City Electric System and the Florida Keys Aqueduct Authority. The CES has met with the FKAA and state officials regarding co-generation.

5. Specific Problems involving the process for Obtaining Exemptions Under the Fuel Use Act.

Unless one or more of the projects outlined in this report are developed, the CES will be totally dependent on fuel oil and would have to be exempted of all restrictions.

6. Problems in Gaining Access to Large Power Projects, as well as to Needed Transmission Facilities.

The most logical approach for solving the CES's energy problems and reduce the dependence on oil is to construct a transmission line to the Florida Grid as explained in the first section of this report. The CES has tried to join with the Florida Keys Electric in the construction of this transmission line through their service area, parts of which are now under construction, but we have been unable to contract with them for joint ownership of this portion of the line. The primary reason for this problem has been the CES inability to finance this project.

As previously stated there is a possibility that the balance of the line to be constructed in the Florida Keys Electric area could be constructed without sufficient capacity to supply some energy to the CES. If the CES misses the opportunity to join in this project, it will be impossible for the CES to tie with any other electric system in the future.

CONCLUSION

The CES has one of the highest electric rates in the nation ($.088 per kwh), primarily due to high oil cost and inefficient generation units.

The CES has experienced no growth in the past 10 years because of a large pull-out of military in this area. In the early 70s the military represented 40% of our total sales, now it is 18%. This military pull-out also affects other businesses and residences in the area.

Due to the CES's financial condition, which continues to become serious as sales decline, the CES is unable to financially implement any of these programs without economical assistance from the government.

Two years ago, the CES had rotating brownouts for 30 days because the two largest generation units were out of service and we did not have sufficient generation capacity to meet the demand.

It is difficult to render dependable service to our customers with the CES being an island system.

A large portion of our generation equipment is nearing 30 years of age and will have to be replaced soon and these programs would greatly increase the System's reliability.

The City of Key West, Florida qualifies for the 1980 HUD's Distressed Community Designation. Without implementing one or more of these projects, adequate electric service to the CES's customers with a minimum of oil burned is impossible.

Very truly yours,

UTILITY BOARD - CITY OF KEY WEST
"CITY ELECTRIC SYSTEM"

John T. Doughtry
Manager

JTD/a

LUBBOCK POWER & LIGHT
916 Texas Avenue P.O. Box 2000 Area Code 806-763 9381
LUBBOCK, TEXAS 79457

May 19,1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street N.W.
Washington, D.C. 20461

Dear Sir:

This letter has been prepared in response to your request, the Federal Register and in the public meeting, for information concerning the Fuel Use Act of 1978 (FUA) and its effect on small utilities.

Lubbock Power and Light's (LP&L) generation system consists of 235 MW of capacity where the largest unit is a 54 MW steam unit. Our system is also one of the few in the country where we have direct competition with another electric utility within our city limits.

The FUA legislation as it now stands will force our municipal out of business. Listed below are the reasons:

A. Coal Conversion Problems:

1. Our generation units consist of diesel machines, combustion turbines and steam units designed specifically to burn natural gas or No. 2 fuel oil. The conversion of any of these units to burn coal would require completely rebuilding the boilers and the majority of the system auxilaries along with the addition of electrostatic precipitators and a SOx scrubbing system. Since our largest unit is 54MW, the cost of this conversion would be several times the initial investmet.

2. In order to maintain our system reliability, any new coal plant would consist of several smaller steam units of which the largest would not exceed 70MW. The costs of building coal units in the size needed to meet our system needs is again several times that of the more conventional 500-600 units.

3. In either of the cases above, large amounts of capital are required. LP&L serves approximately 30,000 meters. In this

time of high interest rates, the costs per meter needed to carry the ownership costs for this large capital investment, would impose an unreasonable penalty on our customers.

4. The ability of LP&L to secure up to 100 million dollars from the bond market is also very questionalbe due to our size and competitive status. If the funds were secured, the interest rate charged would be much larger than that charged to larger utilities to justify the lender's increased risk.

5. In summary, FUA's impact on LP&L in requiring our plants to be converted to coal or in requiring us to construct new coal facilities would unreasonably penalize our customers, and destroy our ability to compete with the larger utility also serving our area, which would force us out of business.

B. New Energy Technologies: The high costs associated with unusual technologies for energy production along with the questions of risk and reliability make it difficult for a community of this size to experiment with these technologies. This community has an active program to encourage solar water heating and wind generation and LP&L has developed a contract to buy any surplus power from any new technology. The amounts expected to be available in the forseeable future are extremely small and sufficient to make a significant impact on our energy needs. LP&L is currently negotiating with Carbon Dioxide Technology Corporation in an effect to supply CO_2 from our plant exhausts to be used in repressurizing older oil wells in the area and thus increase the area's oil production.

C. Joint Participation in other Projects: Due to the relatively scarce population density of our area, new generation projects are few and far between. However, when projects are planned relatively near to our area, they are usually sized to meet the need of only the builder. We are limited to those projects fairly close due to the excessive costs associated with high voltage transmission lines of a sufficient size to transport our relatively small needs. Other utilities in the area have shown no interest in the wheeling of power or even stated that surplus transmission capacity exists. Therefore, it is not likely that we will be involved in a joint project of any size in the near future.

D. Recommendation to help Small Utilities Comply with the Intent of FUA:

Most utilities providing service to areas the size of Lubbock are facing the problems stated above. Therefore, we offer the following recommendations:

1. Utilities of less than 400 MW total generation are affected much more severly than larger utilities by FUA. Also, the availability of natural gas in our area is plentiful and should remain plentiful for several decades. In addition, utilities of this size use a small amount of fuel in their totality when compared to almost any of the larger utilities. We, therefore, recommend that utilities under 400 MW be allowed to use natural gas and be exempted from FUA due to the disproportionate

impact of FUA, especially when those utilities are municipals or serve a relatively low population area.

2. When a major project is being proposed by a larger utility, we recommend that legislation require the larger utility to offer ownership shares in that project to its neighbors and specifically to small utilities close by.

3. Small utilities should also receive some degree of preference in using the suplus of existing transmission lines and in all forms of wheeling arrangements.

4. Small utilities should receive preference in the purchase of synthetic liquid and gaseous fuels compatible with existing small plants. This should be granted since these utilities are much more restricted in alternatives they can consider to meet their generation needs than in larger utilities with more people and capital resources.

5. With respect to the limited manpower and capital available to small utilities, the basic requirements and data needed to apply for an exemption should be reduced. Specifically, due to small utilities small impact on the oil and natural gas availability in this country, several short cuts should be provided to ease processing time and data requirements necessary in getting an exemption. Also, the presently severe financial test required to start almost all the exemptions should be eased off to be more in line with the small utilities limited financing avenues.

In summary, the FUA legislation as it now stands will heavily penalize the consumers of a small utility and in most cases force that utility out of business.

Please keep us informed of any other opportunities to express our opinion and keep us informed of any developments in the FUA program which will affect our area.

Sincerely,

Carroll McDonald

CARROLL MCDONALD
Director of Sales & Service

CM/pm

cc: Larry Cunningham, City Manager
Kent Hance, Representative

CITY OF MORGAN CITY

COUNCILMEN:
LARRY J. DOIRON
ANTHONY J. GUARISCO, Sr.
JOHN T. JOHNSON
CEDRIC S. LAFLEUR
JESSIE H. VOISIN

DR. C. R. BROWNELL
MAYOR

May 21, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street N.W.
Washington, D. C. 20461

Gentlemen:

With regard to the notice in the Federal Register dated April 17, 1980, the City of Morgan City wishes to issue these written comments on the possible changes of the Powerplant and Industrial Fuel Use Act of 1978.

1. Section 103 Definitions (page 5)
   The term "alternate fuel" under the definition "liquid, solid, or gaseous waste by products of refinery or industrial operations which are commercially unmarketable, either by reason of quality or quantity, as determined under rules prescribed by the Secretary;" should not be left vague and very inaffective as presently written. We therefore suggest the insertion of the following:

   > All products of refinery and industrial operations having an initial boiling point in excess of 800°F are considered alternate fuels. Additionally other waste products whose characteristics are such that conventional boiler usage would require extensive modifications can be utilized in fluidized bed or other gasification methods.

2. Section 103 Definitions (page 5)
   The term "electric power plant" and "power plant" are too small and will place unfair advantage to the larger utilities. The municipality having nameplate ratings of 250MW or smaller should be eliminated from the fuel use act requirements.

3. Section 212-Permanent Exemptions (page 14)
   The present Act indicates that mixture of fuels shall not be less than 25 percent of natural gas with coal or another alternate fuels.

   In as much asthis will directly vary regarding retro-fits of air feed gasification to existing boilers the percentage of 25% eliminates the more economical air gasification method. This should be changed to read as follows:

   > "Where air gasification of coal or alternate fuels are utilized to manufacture gas for existing boilers are implemented; the mixture of fuels shall be allowed to whatever percentage required based on volume to

Post Office Box 1218 • Telephone 504-385-1770 • Morgan City, Louisiana 70380

achieve flame requirements based on accepted safety standards."

4. Title III Section 301 (Page 19)
The act says natural gas cannot be used any greater quantities than used in 1974 through 1976.

This section should not reflect the usage in a recessional period of 1974 through 1976 when consumption was slightly curtailed. Additionally this should have growth provisions for small municipalities such as Morgan City so as not to place undue hardships and disadvantages to the small municipalities.

5. Title 5 Section 501 (Page 37)
The act stipulates 1500 HRA as the basis of determining minimum peakload requirements.

This requirement achieves a maximum value of 17.12% and should be changed to a value approximately 40% so as to be capable of utilizing existing investments in gas burning boilers through the remaining period of their useful life. This should therefore be changed to read 3500 hours.

6. Title VII - Administration and Enforcement
The filling of exemptions on a fee charged basis as outlined in the act will place unfair disadvantage on small municipal generating facilities and should be eliminated.

In addition to these specific comments we wish to issue general comments as follows:

A. The Fuel Use Act on restrictions of Natural Gas is in direct conflict with Executive Order pertaining to curtailing import oil. At the present 50% of our oil is imported and a very small percentage of gas is imported. This fuel use act only says natural gas cannot be used after 1990 and therefore is in direct conflict with Executive Order and desire of the United States.

B. The use of adjectives such as "available and marketable as defined by the Secretary" is not in the best interest of this national concern for energy usage. This is especially true if after use of a fuel it is then recognized as being marketable.

C. The act is far too restrictive on the small municipalities with only approximate 5,000 KW of usage as being the dividing line. This limitation could be placed much higher with little effect on the entire nation.

D. The act does not address the local fuel supplies in any manner nor does it address the conditions such as water llmitations we cite the following areas:

   a. Oil and gas prominence in Gulf South
   b. Coal prominence in Northwest and West
   c. Arid areas in West are necessitating additional water supplies for slurry coal pipelines
   d. Alternate fuels of refinery's in West Gulf South and Great Lakes areas.

If local conditions are not addressed in the National Fuel Use Act additional transportation of acceptable fuels will place the transportation of coal in a virtually impossible circumstance

E. Coordination of other areas of federal regulations require more flexibility in the Fuel Use Act. The areas of Safety, Environmental, Natural Gas Act and Fuel Use Act are often placing users of energy in direct conflict with other areas of federal concern. With this in mind, the Fuel Use Act Should be modified to a great extent to eliminate any reference to vagueness or direct conflicts. We certainly appreciate this opportunity to comment on the Fuel Use Act and would appreciate your consideration of the points we have raisedin your comments to Congress in any future requested changes.

Very truly yours,

CITY OF MORGAN CITY

C. R. Brownell
Mayor

CRB:CAA

TMPA

erving the cities of Bryan, Denton, Garland & Greenville

May 22, 1980

Mr. Allen W. Starr
Division of Power Supply and Reliability
U. S. Department of Energy
2000 M. Street, N.W.
Washington, D. C. 20461

SUBJECT: P-9205
Comments Concerning Problems of Compliance with the Power Plant and Industrial Fuel Use Act of 1978

Dear Mr. Starr:

The following comments are in response to the April 17, 1980 Federal Register notice regarding comments relative to Section 744 of the Power Plant and Industrial Fuel Use Act of 1978 (FUA). Section 744 requires the Department of Energy (DOE) to conduct a study of the problems of compliance with FUA experienced by electric utilities with a total system generating capacity of less than 2,000 MW. Our review of FUA as it impacts the TMPA system concludes the following points.

The Texas Municipal Power Agency (TMPA) wishes to file a system compliance option (SCO) exemption petition to cover the existing electric power plants currently owned by the Cities of Garland, Texas, Greenville, Texas, Bryan, Texas, and Denton, Texas. The Economic Regulatory Administration (ERA) has commented that TMPA cannot file such an exemption because TMPA does not own or operate the existing power plants in question. We contend that the existing power plants are controlled or operated by TMPA by virtue of an economic dispatch configuration established by TMPA at the request of the Cities. In addition, we contend that ERA cannot properly interpret its own regulations at this time because power plant "operation" is not defined in the regulations. We see a major problem in that the FUA does not adequately address the rights of TMPA as a filing entity under the system compliance option exemption regulations. Our only recourse is to pursue the legal interpretation of the question. Depending on the length of this process TMPA may find that in order to remain eligible for a system compliance option exemption it will have to prepare and submit an SCO exemption petition prior to the August 1, 1980 filing deadline. If TMPA waits for a legal interpretation of this question past August 1, 1980 without satisfying the deadline requirements it will presumably lose the right to obtain a system compliance option exemption. The uncertainty involved in this problem may require us to incur the expense and effort of developing an SCO exemption petition that may eventually be unacceptable to DOE

exas Municipal Power Agency 600 Arlington Downs Tower Arlington, Texas 76011 (817) 461-4400

Our analysis of the SCO regulations illustrates yet another problem unique to power pools such as ours. Under the current SCO regulations each petitioner will be able to burn a certain volume of gas through the year 1999. This volume allowance cannot be exceeded except for certain limited peak load or emergency situations. In our particular configuration if each City obtains an approved SCO plan each City will have an annual volumetric gas limitation. These gas volumes are used to satisfy the generation requirements of the TMPA system under economic dispatch. Since certain Cities will have to generate to satisfy our pool requirements it is likely that these Cities will consume their SCO gas volume limitation before they satisfy their portion of pool generation. When this happens the units will most likely have to switch to burning oil. The problem we see is that within our pool certain Cities will not consume their SCO gas volume limitations while other Cities will be called on to use 100% of their SCO gas allowance plus burn expensive oil. We feel that these restrictions are contrary to the concept of power pooling, will result in the burning of otherwise unnecessary quantities of oil and will increase the cost of electricity to our customers unnecessarily. If we were allowed to operate under an SCO plan that treated the four individual City gas allowances like a pool resource our customers could recognize a $30 million savings over a ten year period.

The regulatory burden of FUA is considerable and has created significant difficulties in the development of an acceptable compliance strategy. The difficulties include:

1. FUA regulations are published in a random fashion in the Federal Register.

2. Our compliance strategy has been based on "interim" FUA regulations. If the "interim" regulations are changed these revisions could easily affect our selected strategy at this time. Given the deadline of the SCO strategy, we find this problem of particular concern.

3. The FUA discretionary fuel prohibitions add to the uncertainty in developing an acceptable compliance strategy. The discretionary fuel prohibitions may negate our long term planning effort because future decisions by DOE in this area can affect our system fuel mix. Such changes could cause power plant conversions or early retirement in the TMPA system. Both results may increase the cost of electricity to our customers in the future.

4. Our system has 24 existing steam and gas turbine generating units. We anticipate the need for some of these units through 1999. The units required in this period can be gas or oil fired. If the regulations on gas are imposed as we understand them we see no acceptable alternative but to burn expensive oil in these units.

Based on our understanding of the FUA and the problems identified above, we recommend that the FUA be revised to either permit TMPA the right to file and receive an SCO exemption covering the existing power plant units of the Cities or allow the four (4) Cities to file individual SCO exemptions that would allow the Cities to exchange their respective SCO gas allowances between the power pool participants.

Respectfully,

Joel T Rodgers

Joel T. Rodgers
General Manager
Texas Municipal Power Agency

jk

TELEPHONE 714-355-1112

IMPERIAL IRRIGATION DISTRICT

OPERATING HEADQUARTERS • IMPERIAL, CALIFORNIA 92251

May 21, 1980

Small Utilities Study
Office of Utilities System
Department of Energy
2000 "M" Street N.W., Room 4002
Washington, D.C. 20461

Subject: Written Comments on Problems that FUA Imposes on Small Utilities [Those Utilities with a Total Generating Capacity of Less Than 2000 Megawatts]

Gentlemen:

Imperial Irrigation District (IID) has encountered several problems as a result of the Fuel Use Act. A few of those problems are explained in this letter.

Attached please find letters from the IID to the Department of Energy (DOE) and answers to those letters from the DOE regarding compliance with the Fuel Use Act in licensing Rockwood Units No. 1 and No. 2; a two-unit 49.5-mw peaking plant. This is a continuing problem for the IID that is now over a year old. It should be noted that the IID has tried in narrative form to comply with the regulations as published in the Federal Register, but in every case has been required to fill out the proper DOE forms. Help in streamlining this operation would be advantageous.

IID is an isolated power system, except for the Western Area Power Administration (WAPA) interconnections with the Parker-Davis Project.

Prior to the FUA, IID planned to install a medium-sized (100 - 200 mw) combined-cycle plant in stages as required by projected load growth. However, the use of oil and gas for an intermediate-load plant is no longer allowed and IID's plans have to be revised. Projected load growth indicates that by 1983, 25 - 50 mw will be required, with an additional 100 mw required in 1985. The only type of plant that can be constructed in this short time is a peaking plant and peaking plants can only be licensed to operate 1500 hours per year if they use oil or natural gas.

The probability of locating a coal plant in California of a size suitable to the needs of IID is quite remote and, at best, an eight-year process.

IID is currently working with adjacent utilities in an effort to secure transmission service and interconnection points. Any assistance under any of the Energy Acts that DOE or Federal Energy Regulatory Commission (FERC) can offer would be greatly appreciated. Should transmission service and interconnection be accomplished in a timely manner, the above peaking plants could probably be replaced, or at least deferred, by firm power contracts. IID realizes that there will be coal power available in Arizona and New Mexico in the mid 80s, but without transmission paths, this energy will not be available to IID.

To meet the 1990 goal of 50 percent reduction in oil consumption, interconnection, transmission service, and either participation in plants in Arizona and/or New Mexico, or firm power contracts, will be required.

Thank you very much for the opportunity to comment on these problems.

Yours very truly,

R. OGILVIE
Manager, Power Department

RO:clm
Enclosures

City of Clarksdale

PROGRAMMED FOR PROGRESS!

RICHARD M. WEBSTER, JR
MAYOR

POST OFFICE BOX 940
CLARKSDALE, MISSISSIPPI 38614

May 21, 1980

Dr. Alan W. Starr
Room 4103
Division of Power Supply & Reliability
U. S. Department of Energy
2000 M Street, N. W.
Washington, D. C. 20461

Re: Study of Small Electric Utility Systems pursuant to Section 744 of the Power Plant and Industrial Fuel Use Act of 1978

Dear Dr. Starr:

I am enclosing the written comments of the City of Clarksdale, Mississippi in response to the request issued April 11, 1980 by the acting Assistant Administrator for Utility Systems. The original of these comments has been mailed to Room 4002.

Please note that the City of Clarksdale would like very much to be the subject of a case study by the Economic Regulatory Administration and would be pleased to begin immediately cooperation with your office in such a study.

Yours very truly,

Richard M Webster, Jr.

Richard M. Webster, Jr.
Mayor

Enclosure

JAMES HICKS
COMMISSIONER

THOMAS E. GARMON
COMMISSIONER

HENRY W. ESPY, JR
COMMISSIONER

RICHARD WEISS
COMMISSIONER

UNITED STATES DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

RE: Study of Small Electric Utility Systems pursuant to Section 744 of the Power Plant and Industrial Fuel Use Act of 1978

WRITTEN COMMENTS OF THE CITY OF CLARKSDALE, MISSISSIPPI

The City of Clarksdale, Mississippi (hereinafter referred to as "Clarksdale") submits the following comments pursuant to the request for comments issued April 11, 1980, by the acting Assistant Administrator for Utility Systems of the Economic Regulatory Administration.

Clarksdale is a small municipality with a population of approximately 23,000 people and is located in the northwest portion of the State of Mississippi in the Mississippi Delta region. Clarksdale has a very high incidence of poverty and a large minority population.

Clarksdale began operating its own municipally-owned electric generation and distribution system in 1900. The generating plants of the City have steadily grown, of course, and at present Clarksdale has an installed design generating capacity of approximately 63,000 kw. In 1946, Clarksdale began using natural gas for generation. The conversion to natural gas in 1946 occurred at a time when there were large volumes of natural gas available for sale with no other prospective consumers of natural gas. The climate of the area is such that the use of natural gas by the generating plant is lowest during the winter months at a time when the demand by other consumers of natural gas is at its highest. Conversely, the demand by the generating plant is at its highest during the summer months when the use of natural gas by other consumers is at its lowest.

Thus for many years, Clarksdale was a valued customer of its natural gas supplier. Clarksdale, being consistently assured of the supply of natural gas, designed each new generating unit to operate solely on natural gas or fuel oil. Fuel oil was used only as a standby fuel with the actual use of fuel oil occurring only an average of eight (8) to ten (10) days each year. The use of the fuel oil occurred on extremely cold winter days when the demand by residential customers on the natural gas supplier's pipeline reached a peak. Under these circumstances, Clarksdale installed its generating facilities in such a manner that only natural gas or fuel oil could be used. The following is a brief description of each generating unit with the year of its installation.

GENERATING FACILITIES

FACILITY	DATE INSTALLED	SPECIFIED FUEL	DESIGN CAPACITY
Third Street Plant			
Unit #4 (Steam Unit w/ Turbo Generator)	1945	Gas or #6 Oil	3500 KW
Unit #5 (Steam Unit w/Turbo Generator)	1952	Gas or #6 Oil	7500 KW
South Plant			
Unit #6 (Steam Unit w/Turbo Generator)	1956	Gas or #6 Oil	6250 KW
Unit #7 (Steam Unit w/Turbo Generator)	1962	Gas, #2 Oil, or #6 Oil	7500 KW
Unit #8 (Simple Cycle Gas Turbine)	1965	Gas or #2 Oil	12,400 KW (base load) 14,400 KW (peak load)
Unit #9 (Combined Cycle Steam and Gas Turbine)	1972	Gas or #2 Oil	24,750 KW (Gas) 24,450 KW (#2 Oil)

The last unit is a combined cycle steam and gas turbine which now serves as Clarksdale's base load unit. The contract for this unit was let in 1969 with assurances from Clarksdale's natural gas supplier that natural gas supplies were plentiful and there did not appear to be any problem in the supply in the future. In performing its study on the feasibility of this unit, Clarksdale was furnished information that the maximum curtailment on its gas supply would be ten percent (10%) which could possibly occur in the distant future. Thus, Clarksdale proceeded with the design and installation of this combined cycle steam and gas turbine which became operable in 1972.

Shortly prior to April 1, 1975, Clarksdale was notified by its intrastate natural gas supplier that the delivery of gas to Clarksdale's generating system would cease entirely on April 1, 1975. The curtailment was allegedly the result of a supply shortage being experienced by the interstate jurisdictional pipeline from which Clarksdale's intrastate supplier acquired its gas for the Clarksdale area. Although legal remedies were pursued vigorously by Clarksdale, the 100% curtailment of the natural gas supply was implemented on April 1, 1975. Clarksdale suffered extremely difficult operational problems during the period of curtailment. The machinery and equipment of its generating system were simply not designed to operate full time on fuel oil, and Clarksdale experienced many equipment failures and electrical outages during the curtailment, including a boiler explosion during the year 1976. From April 1, 1976 until 1978, Clarksdale burned natural gas in its generating units only during the emergencies created by the failure of the fuel oil supply equipment and during March, 1976. The total volumes of natural gas burned in these units in 1975 and 1976 were relatively insignificant.

An extremely unfortunate coincidence is that during the calendar year 1977, Clarksdale was able to adjust temporarily to the natural gas curtailment and the volumes of natural gas burned by its generating units during that year are negligible. Legal proceedings being pursued by Clarksdale eventually culminated in the resumption of natural gas delivery. In 1978, Clarksdale's intrastate supplier was able to integrate its intrastate gas field with its supplies from the jurisdictional pipelines (which also experienced an "increase" in supplies in 1978), and full deliveries of natural gas to Clarksdale resumed. The apparently arbitrary selection of the year 1977, as specified in the Fuel Use Act as the year upon which the future use of natural gas rests, is patently discriminatory against Clarksdale which burned natural gas 33 out of the last 34 years - the one year it did not burn natural gas was 1977. Two of the three years used to determine the ratio of natural gas allowed to be burned in generating units are years during which Clarksdale was under 100% curtailment. The failure to burn natural gas in 1977, and the failure to burn the usual quantities of natural gas during 1975 and 1976 were the result of events totally beyond Clarksdale's control.

Clarksdale can use no alternate fuel and has no source from which outside power and energy can be purchased at the present time. Clarksdale has been actively seeking alternative sources of power and energy. However, these efforts to date have met with no success.

Clarksdale has, for four years, been seeking to obtain an ownership interest in the Grand Gulf nuclear power plant being constructed by Mississippi Power & Light Company and Middle South Utilities. Mississippi Power & Light Company has denied Clarksdale the opportunity to participate in the ownership of this unit and legal proceedings are now pending before the United States Nuclear Regulatory Commission. No prediction can be made as to the success of Clarksdale's efforts to obtain this source of power.

In January, 1979, Mississippi Power & Light Company announced that it planned to construct a 700,000 kw coal fired generating unit in DeSoto County, Mississippi, approximately 50 miles north of Clarksdale. Mississippi Power & Light Company indicated to Clarksdale that it would be amenable to Clarksdale's ownership participation in this unit. Clarksdale immediately began efforts to reach an agreement with Mississippi Power & Light Company on acquiring an ownership interest in these units. Clarksdale had at least two negotiating sessions with Mississippi Power & Light Company, but Mississippi Power & Light Company announced in May, 1979, that plans for the construction of this generating unit had been shelved to be reconsidered at some future date. There has been no indication of when this unit will again be considered. Clarksdale has been informed that the Middle South system has changed its plans to construct the first of these coal-fired units in the Mississippi Power & Light Company area but intends to build the first units in another of its operating company areas.

Clarksdale has attempted to purchase wholesale power from both Mississippi Power & Light Company and from outside the State of Mississippi. Mississippi Power & Light Company has to date refused to sell to Clarksdale part of the power requirements of Clarksdale. Legal proceedings are now pending before the Nuclear Regulatory Commission on this denial by Mississippi Power & Light Company. No prediction can be made as to the outcome of these proceedings nor when this issue can be resolved.

Clarksdale has also entered into a contract on at least one occasion with the City of Lafayette, Louisiana, for the purchase of wholesale power from that city. Lafayette was to deliver the contracted power and energy to Gulf States Utilities, who in turn would deliver it to Mississippi Power & Light Company at the point where the 500 kv transmission line belonging to Mississippi Power & Light Company connected with the 500 kv transmission line owned by Gulf States Utilities. However, Mississippi Power & Light Company refused to accept delivery of power and energy from Gulf States Utilities, asserting that no interconnection agreement existed between Gulf States Utilities and Mississippi Power & Light Company. This dispute is also the subject of legal proceedings before the Nuclear Regulatory Commission. In addition, Mississippi Power & Light Company attempted to file an unexecuted interconnection agreement with the Gulf States Utilities without service schedules attached. The Federal Energy Regulatory Commission rejected the filing as improper and, as of this date, Mississippi Power & Light Company has not attempted to refile.

Clarksdale, in further pursuit of alternative power supplies, lead the efforts to obtain the passage of legislation by the Mississippi Legislature in 1978, which permitted municipally owned utilities to join together to form joint action agencies. Clarksdale personnel drafted the legislation which was ultimately adopted by the Mississippi Legislature. Clarksdale was instrumental in the formation of the joint action agency known as the Municipal Energy Agency of Mississippi, which is chaired by the Mayor of Clarksdale. The Municipal Energy Agency of Mississippi has been actively pursuing alternative power supplies on behalf of its members, including Clarksdale. The Municipal Energy Agency of Mississippi ("MEAM") and Clarksdale have diligently sought allocations of power and energy from the Southeastern Power Administration. These efforts have been unsuccessful and it appears that the Administrator of the Southeastern Power Administration will adopt a proposed marketing policy which will forever exclude MEAM and its member cities, including Clarksdale, from receiving any allocation of power from the Southeastern Power Administration.

MEAM has applied to the Federal Energy Regulatory Commission for a preliminary permit to study the feasibility of the acquisition, construction and operation of hydroelectric facilities at four low-head flood control dams and reservoirs in northwest Mississippi. However, it is anticipated that the total energy to be obtained from the successful operation of hydroelectric facilities at these sites will fall far short of providing a significant portion of the energy requirements of the customers of MEAM.

Thus, Clarksdale, although diligently pursuing alternative sources of power, finds very little reason for optimism. The prohibitions imposed by the Fuel Use Act on Clarksdale, combined with the difficulty of obtaining a practical alternative power supply, presents a gloomy picture for the future of the Clarksdale utility even though Clarksdale probably has a much longer history of using natural gas for generation than the majority of other gas using generating systems. The Fuel Use Act penalizes Clarksdale perhaps more severely than most other utilities. Only small quantities of natural gas were burned in 1975 and 1976 during a period of curtailment and practically no gas was burned in 1977. The Fuel Use Act requires gas to have been burned in 1977 in order for gas to continue to be burned prior to 1990. Thus, without exemptions, Clarksdale will be completely prohibited from burning natural gas. This imposes a very severe burden on this small utility.

Clarksdale appears to be placed in a position of seeking a permanent exemption or utilizing the system compliance option. However, the cost of meeting the burden of proof imposed on the utility seeking a permanent exemption, particularly those requiring a fuel decisions report, is onerous to a small utility like Clarksdale. Similarly, the cost burden for preparing, and obtaining acceptance of, a system compliance option plan is very great for a city like Clarksdale. The requirement of overly burdensome and expensive accumulations of data to meet the burden of proof and to satisfy the requirements of the statute and the regulations create serious problems for a utility with an annual income of $6,000,000.

Clarksdale notes that the Economic Regulatory Administration will perform case studies for a representative sample of utilities. Clarksdale would like very much to submit to a study by the Economic Regulatory Administration and offers to do so. It is believed that nearly all problems that are faced by small utilities are also faced by Clarksdale, and a thorough study can be made of these problems in the Clarksdale utility.

Respectfully submitted,

CITY OF CLARKSDALE, MISSISSIPPI

By: Richard M Webster Jr
Richard M. Webster, Jr., Mayor

Board of Public Works

City of Fulton

FULTON, MISSOURI
65251

BOARD MEMBERS:

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JOHN E. BATES
Superintendent of Utilities

BYRON DYSART
Comptroller

(314) 642-6655

May 23, 1980

Mr. Alan W. Starr
Chief, Source Technology & Economics Branch
Division of Power Supply & Reliability
Economic Regulatory Administration
Washington, D.C. 20461

Dear Mr. Starr:

Fulton's power plant was constructed 1967-1971 and consists of three (3) internal combustion engines and one (1) combustion turbine, a total of 32.5 megawatts. All of this equipment can be operated 100% on #2 oil or on natural gas with approximately 5% #2 oil for ignition. There is no known alternative fuels that will work in this equipment.

All of this equipment should have a useful life of 40 years with proper maintenance. The revenue bonds covering this equipment will not be paid off until 1991 and even then the expected life of the plant would extend to the year 2007.

Fulton is tied to a state wide network through Associated Electric Co-op of Missouri and we have contracted for additional power through their network, for coal produced electricity but our own equipment will have to be base loaded at least through the severe cold winter months and through the peak periods of summer.

Early in 1979 we were told by the Department of Energy representatives to arrange for gas for our power plants in order to reduce oil imports. We did this and our present gas supplier, Panhandle Eastern, predicts we will have all the gas we need for our operation through 1990.

We belong to the American Public Power Association and feel that they have been representing their members before hearings for D.O.E. and E.R.A. and other branches of our government but the scene changes so fast and the mood of congress shifts from week to week that none of us can plan effectively for the future needs of our communities.

I hope this is the information you are seeking. I will be happy to furnish any additional data you might ask for.

Sincerely,

J E Bates

John E. Bates
General Superintendent

BOARD OF PUBLIC WORKS
CITY OF FULTON, MISSOURI

JEB/jp

NEW EXCHEQUER DAM
AND POWERHOUSE

MERCED IRRIGATION DISTRICT
2423 L STREET
MERCED, CALIFORNIA
95340
MAILING ADDRESS: P. O. BOX 2288
PHONE: (209) 722-5761

May 28, 1980

Alan W. Starr
Division of Power Supply and Reliability
U. S. Department of Energy
2000 M Street, N. W.
Washington, D. C. 20461

Dear Mr. Starr:

Please be advised that our District's two generating plants are both hydroelectric and therefore use no gas, oil or coal.

Sincerely,

TOM RETA
Chief Engr. & Asst. Mgr.

TR:ls

ASSOCIATION OF CALIFORNIA WATER AGENCIES

DIRECTORS:	JOSEPH PLAGENZA President Division 2	RICHARD PARKER Vice-President Division 1	GEORGE MACK Division 3	LESLIE PAPAZIAN Division 4	DONALD PETERS Division 5
STAFF:	HUBERT TRINDADE Assessor-Collector		JAY ANDERSON Secretary-Manager-Treasurer		TOM RETA Chief Engineer

CITY OF TRINIDAD

CITY HALL

TRINIDAD. COLORADO

81082

Electric Power & Light

May 29, 1980

Alan W. Starr
Chief Source Technology & Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Starr:

In response to your letter of problems confronting small utilities concerning FUA 1978, I am reporting the following.

Our plant has 11.5 megawatts capability, in generation. Due to the cut-off of our natural gas deliveries by our supplier, our generation capability has been reduced to 4.9 megawatts.

The City converted one of its 45,000 lb. an hour boiler from natural gas and no. 2 diesel oil firing to coal firing. The cost of this project was $540,000.00.

The boiler conversion was completed and put on the line January 9, 1979. The City has thus learned the boiler did not pass the emissions test specifications imposed by the Colorado Department of Health.

With the loss of natural gas supplies and meeting the coal stack emissions specifications, the small power plants can no longer operate.

Sincerely,

A. J. Schroeder,
Power & Light Superintendent
CITY OF TRINIDAD

AJS/ls

THE CITY OF OTTAWA
CITY HALL
(913) 242-2190
OTTAWA, KANSAS 66067

June 4, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street N. W.
Washington, D. C. 20461

Re: DOE/Fuel Use Act
Small Utility Comments

The City of Ottawa operates a generating system in the 25 MW class, serving 5,192 customers within the City, which has a population of 10,500 people.

The Utility Department of this City feels that section 744 of the FUA/1978 primarily addresses itself to large utility operations. It appears that a utility of our size might be at a great disadvantage when it comes to consideration on essential fuels for generation purposes. Most small systems rely on internal combustion engines, and small combustion turbines, principally gas and oil fired. After some study it is this City's contention that the gas and oil used by the small municipal utilities across the United States represents a very small percentage of the total oil and gas utilization in this nation. We feel the smaller systems do have a place in the future scheme of electrical generation. They provide a market place for off-peak energy for coal-fired and nuclear sources, and relieve burdens on the larger systems on-peak periods. They also provide local reliability, help maintain local employment, and material production which has a bearing on the GNP of this nation.

We feel that your department should agree that a plant of our size could not utilize coal in its present form (with all its handling and transportation costs) as a realistic energy source. This brings forth the thought of present regulatory policies in regards to the pricing of natural gas to energy producing facilities. This City feels that any artifical price raising of natural gas over actual costs justification further distorts the rational development of alternatives.

This utility, like many smaller municipal generating facilities feels it would be unfair for them to be subjected to the same regulatory procedures as the large systems. Smaller systems can ill-afford the expense or the legal and technical impact to pursue exemption applications for co-generation concepts, hardship cases, ect.

Small generating facilities in general need additional time with a realistic cost on gas and oil until alternative technologies emerge making possible use of low-grade energy sources.

We thank you for the opportunity to comment.

Jack E. Davis
Director of Utilities

JED/bao

MARSHFIELD ELECTRIC and WATER DEPT.
MARSHFIELD, WISCONSIN 54449

Phone 715 387-1195
2000 South Roddis Ave.
P. O. Box 670

May 30, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street NW
Washington, D.C. 20461

Gentlemen:

The Marshfield Electric Utility is a municipal utility that serves about 9,500 electric customers and has 39 megawatts (MW) of steam powered generation. This generation is comprised of 29 MW of coal fired generation and 10 MW of natural gas fired generation. #2 fuel oil can be used as an alternate fuel in the gas fired boilers. The price of natural gas is presently about $2.95 per million BTU and the price of #2 fuel oil is about $6.50 per million BTU.

Marshfield uses, on an average, about 2,000,000 therms of natural gas per year. This is used mostly for peaking and some intermediate power generation. To replace the natural gas with fuel oil at the above costs represents an increase of about $710,000.00 per year.

Marshfield presently buys partial requirements power from a private utility. About 50% of the power needs of the City are purchased from this private utility and the other 50% are generated. This produces the most economic mix for our power supply. If Marshfield was to replace the 10MW of natural gas fired generation with firm power purchases under our partial requirements contract, the increase in demand charges per year would be about $734,000.00.

Therefore, like many other small utilities, Marshfield needs natural gas for generation in order to avoid substantial cost increases to its customers.

We would like to address one other problem with the Power Plant and Industrial Fuel Use Act. Marshfield applied for and received a Special Temporary Public Interest Exemption from the prohibitions of sections 301(a)(2) and (3) of this Act. As a condition of these exemptions, we are required to submit to the Department of Energy a system-wide fuel conservation plan. The plan must be set up and monitored to show the specific results of the energy conservation plan. It is readily apparent to us that we do not have the personnel or financial resources to carry out the required plan. We are sure that many other small utilities with limited staff personnel are in similar situations. If the Department of Energy insists on this requirement, Marshfield will have to surrender the Special Temporary Public Interest Exemption it received.

Thank you.

Sincerely,

Robert R. Pawelski

Robert R. Pawelski, P.E.
Utility Manager

RRP:lt

c.c. Ruth Gonze, APPA

CITY OF HIGHLAND

Highland, Illinois 62249

PHONE (618) 654-9801 OFFICE — 1115 BROADWAY

May 30, 1980

Mr. John H. Williams
Div. of Power Supply and Reliability
U.S. Dept. of Energy
2000 M Street N.W.
Washington, D.C. 20461

Dear Sir:

I am writing to you in reply to a letter dated May 21, 1980, from Alan Starr. He requested comments regarding the Powerplant and Industrial Fuel Use Act of 1978. I shall attempt to comment on several of your suggested points.

As background information, Highland operates a municipal electric system. Our peak last year was 17.9 MW and we generated 11.5 MW of it with dual-fueled diesel engines. The remaining 6.4 MW was purchased from Illinois Power Company.

We base load from I.P. and generate to peak shave. Last year, our total system use was 66,450 MWH; we generated 15,125 MWH of this total.

Comments: #1, "Impact of FUA...."
As I understand the FUA, it does not presently affect diesel engine generation. I sincerely hope that these large engines will remain exempt as they are usually one of the only forms of peaking generation available to small municipalities at reasonable costs. Small municipals usually do not have the bonding power necessary to support the purchase of state-of-the-art steam generation equipment selling for $1000 to $1200 per kilowatt. Diesel, at about $350/kw, and combustion turbines at about $200/kw are all that are available in our price range.

Since we cannot afford to purchase base-load (steam) equipment, we are left with peaking units and negotiated, base-load contracts. Such requirements force us to diesel or natural gas fuel sources. The impact of FUA is then an effective block of the purchase of any combustion turbine peaking unit of greater than 10 MW capacity. This extra peaking requirement, which the municipal cannot generate, is then forced onto the base load utility's system--often at the same time as its peak. The extra demand decreases the base load utility's reserve capacity, increases the cost of power to the municipal customers (due to increased demand charges), and the electrical industry as a whole loses some of its ability to meet future load. Suggestion: Could this Act be ammended to apply only to base load units? If intermediate and peaking load units were exempt, small utilities could live with the Act.

#6, "Problem in gaining access...."
This year, the Illinois Municipal Utilities Association was able to get an "Enabling Legislation" bill introduced in the Illinois House and Senate. This introduction was the culmination of several years of work by the IMUA Joint Action Committee. Unfortunately, after the bill made it back to the floor from Committee, the sponsoring Senator pulled it off of the adgenda, and so, the bill has been scrapped for this session.

Legislation enabling municipals to form joint action groups to purchase and/or build their own generating plants has met much opposition in states where it has been presented. Many states now have such legislation, but getting it passed in state legislatures requires more time and money than is necessary. Investor owned utilities see joint action groups as threats to their livelyhood, and so, lobby very strongly against them. Municipals usually do not have the funds necessary to buy the lobbyists for the legislation, so the battle becomes a long one.

Suggestion: Pass a broad-coverage "Enabling Legislation" act on the Federal level which would make joint action groups legal in all states, and so save the ratepayers of both the municipal and investor-owned utilities the costs of the legal hassles which will result otherwise. With the enabling legislation, municipals can get on with the planning and construction of needed generation facilities. Remember that it takes about seven years to build a steam plant, so the longer it takes to get enabling legislation, the farther off those plant completion dates are.

#7, Possible Federal or State Actions
(III) Legislative Ammendments to FUA requiring states to pass joint action legislation.

(IV) Provide funds for "exotic" or "unusual technologies" such as fluidized beds, etc. to small electric systems. Systems which would benefit most from these smaller units should be the ones getting the Federal grants, not the big systems which don't really need the small experimental units.

(V) State action; Pass joint action legislation.

I would like to thank you for the opportunity to comment on this Act.

Sincerely,

William M. Herron

William M. Herron, P.E.
Electric Supt.
City of Highland

cc: D. Williams, City Manager

cm

Town of Wallingford, Connecticut

CHARLES F. WALTERS
GENERAL MANAGER

ELECTRIC DIVISION
DEPARTMENT OF PUBLIC UTILITIES
100 JOHN STREET
WALLINGFORD, CONNECTICUT 06492

TELEPHONE 265-1593

June 2, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy - Room 4002
2000 M Street
Washington, D. C. 20461

Gentlemen:

This utility operates a 22.5 MW oil-fueled steam generating station used for peaking power. Cost of converting existing equipment would have to be spread over few Kilowatt hours. This makes any such conversion project uneconomical.

Although there have been regular opportunities to participate in ownership of existing or planned large generating units, the length of time to negotiate for access to transmission facilities precludes serious consideration of such offerings.

Participation in a mix of existing or proposed generating facilities would be the most economical approach to follow for small utilities. These efforts have often been frustrated by owners of transmission facilities, particularly when they are the wholesale supplier of electricity to the small utility.

Although I am not certain of the "breaking" point, many utilities or agencies below 2000 MW have substantial staff capability that is not present in a utility with a 22.5 MW generating station. My suggestion would be to raise the 100 million BTU limit to recognize the total size of the utility.

Sincerely yours,

Charles F. Walters

Charles F. Walters

GENERAL MANAGER

CFW/rbb

CITY OF COLORADO SPRINGS
COLORADO 80947
P.O. BOX 1103
DEPARTMENT OF PUBLIC UTILITIES
WATER—ELECTRIC—GAS—WASTE WATER

ITILITIES BUILDING
8 S. NEVADA AVE.

CERTIFIED P11 3450951

June 3, 1980

Mr. Allan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and
Reliability
Economic Regulatory Administration
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Starr:

Mr. James D. Phillips, Director of Utilities for the City of Colorado Springs has asked that I respond to your letter of May 21,1980 concerning the impact of the Fuel Use Act on utilities with less than 2000 MW of generation. We, here in Colorado Springs, appreciate having the opportunity to comment on the Fuel Use Act Regulations.

As a point of information, we have hired a consulting firm to assist us in determining the optimum approach to meeting the prohibitions of the Act. In addition, staff personnel have been following the progress of the Fuel Use Act specifically, and the National Energy Act generally, since their inception. We have filed for an exemption under the special rule for a Temporary Public Interest Exemption and are awaiting a ruling by the ERA.

At the present time, the City of Colorado Springs owns and operates 547 MW of thermal generation, 469 MW of which is coal-fired. The remaining 78 MW is oil/gas fired generation and is provided by six smaller units. Because of economics and national interests, these older units are operated only when less expensive power is not available in the region. While these units could not be economically converted to coal-firing, they are still valuable assets in terms of the reliable operation of our system in the event of equipment outages due to malfunctions or maintenance. Therefore, it is to our advantage to operate these units when necessary.

Given the apparent flexibility of the Fuel Use Act, we do not foresee any major impact of the prohibitions on this utility. However, the potential does exist. For instance, if we are not granted an exemption under the special rule, we will be forced to burn oil in these older units to comply with the prohibitions of Section 301 of the Act. This would constitute an economic penalty to our ratepayers and would seem to contradict the intent of the National Energy Policy.

I hope that these comments will be of use to you. Once again, thank you for the opportunity to comment. Please feel free to contact me if you have further comments.

Sincerely,

D. M. Schoen

Don M. Schoen
Superintendent of Planning
Electric Production Division

DMS:DAM:mef

xc: J. D. Phillips
B. G. Godec
D. A. Mrkvicka

AMERICAN PUBLIC POWER ASSOCIATION
2600 VIRGINIA AVENUE NW WASHINGTON DC 20037 · 202/342-7200

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Los Angeles, California
WALTER R. WOIROL
Chelan County Public Utility District
Wenatchee, Washington
ROBERT C. YOUNG
Burlington, Vermont

June 6, 1980

Hand Delivered

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4103
2000 M Street, N.W.
Washington, D.C. 20461

Dear Sir or Madam:

Enclosed are five copies of comments prepared by the American Public Power Association, a national association of publicly owned electric utilities, on the Study of Compliance Problems of Small Electric Utility Systems With the Powerplant and Industrial Fuel Use Act of 1978.

Sincerely,

Ruth Gonze

Ruth Gonze
Assistant Legislative
Director

RG:ep

Enclosures

Comments of the
AMERICAN PUBLIC POWER ASSOCIATION

on the
Study of Compliance Problems of Small Electric Utility Systems
with the Powerplant and Industrial Fuel Use Act of 1978

Economic Regulatory Administration
June 6, 1980

The following comments are submitted in regard to ERA's Small Utilities Study conducted pursuant to Sec. 744 of the Powerplant and Industrial Fuel Use Act (FUA) by the American Public Power Association, a national association representing 1,400 publicly owned electric utilities in 48 States, Puerto Rico, the Virgin Islands, Guam and American Samoa.

About 680 publicly owned utilities generate part or all of their electric power requirements. Virtually all would be "small" utilities as defined by Section 744 -- having under 2000 MW of generating capacity. We believe, however, that electric systems with generating capacities over 1000 megawatts do not have difficulties in complying with FUA which are substantially greater or different in nature from those experienced by utilities with over 2000 megawatts of capacity.

Major differences in resources, types of generating equipment, and practicable fuels, and increasingly greater burdens in complying with the Act, exist for utilities with less than 200 to 300 megawatts of capacity. Utilities with less than about 50 megawatts of capacity can probably be distinguished from this group: such extremely small electric systems almost everywhere lack the resources in staff, expertise, revenues, power supply choices, and bargaining power with potential wholesale power suppliers to meet requirements which may be imposed on them either by the statute or by regulation. The total amount of fuel used by these extremely small utilities is a minute percentage of total utility consumption. The best solution to their problems would be a legislative amendment exempting them entirely from coverage by the Act. If that is not done, then separate, simplified rules imposing minimum requirements should be adopted for these systems. Separate criteria for exemptions and administrative requirements should be established as well for the larger class of small utilities for which compliance with the Act and regulations is a serious, and often untenable, burden.

Among publicly owned generating systems within the continental United States, 151 had steam generating capacity in 1977 (using oil, gas, coal, and uranium), with a mean capacity of 40 megawatts. 128 have less than 200 megawatts of capacity; 90 have less than 50 megawatts of capacity. Sixty-five systems have gas turbine generating facilities, with a mean capacity of 26 megawatts. Sixty-two have less than 200 MW, and 46 less than 50 megawatts. About 500 systems use internal combustion engines. These systems include many of the country's smallest generating utilities. Their survival as independent generating utilities may depend upon the continued exclusion of internal combustion engines from coverage by the Fuel Use Act.

The Gas Use Ban

The Fuel Use Act poses a number of problems for small electric utilities. The most serious arise from the Act's prohibition on gas use after 1989 and its limitation on gas use before 1990 based on 1974-1976 gas use levels. Small steam or gas turbine units have only two alternatives to using natural gas: using petroleum or shutting down. Resorting to petroleum is exhorbitantly expensive for electric consumers; increases petroleum imports; and may seriously affect the competitive position of the utility relative to larger surrounding investor owned utilities.

The Act's limitations on natural gas use are proportionately more serious for small utilities than for large because many small systems have been more dependent on oil and gas than large systems in the same region; because investments in small coal facilities are proportionately less economic, and below about 200 MW of capacity usually are economically unjustifiable; because small utilities are subject to a variety of anti-competitive practices limiting their access to transmission networks and to participation in large generating projects on reasonable terms; because small utilities forced by FUA to purchase power at wholesale are inadequately protected from unfair rates charged by large power suppliers; and because small utilities do not have commensurate resources to petition successfully for exemptions from the Fuel Use Act.

The Burdens of the Exemption Process

Exemptions provided under the Fuel Use Act and ERA's implementing regulations are so complicated, so expensive, and so demanding of the expertise of consultants and lawyers, that they are effectively out of reach for many systems. It is probably the general case that small utilities cannot hope to complete successfully an exemption petition containing difficult proofs, or pay substantial filing fees, or meet complex terms and conditions, for obtaining the permanent and temporary exemptions for which they may well qualify under the Act.

As it is presently administered, the Act is likely therefore to threaten the survival of small electric systems dependent on generation with natural gas, certainly in 1990, or before then upon termination of the temporary public interest exemption.

Strategies for Compliance with FUA

Several strategies may permit compliance with the Act, and survival, for individual utilities. No available strategy has generalized application, and all present serious drawbacks. Participation in large nuclear generating projects built by larger utilities may be obtained, in some cases, and is facilitated by antitrust review provisions of the Atomic Energy Act. No similar legal help exists to enable participation in large coal-fired plants. In addition, participation in a distant nuclear or coal-fired plant entails obtaining transmission services which may be denied or offered only on punitive terms.

New nuclear or coal-fired generation cannot be constructed independently on a small scale; the smallest economic capacity for a new coal-fired plant is probably about 200 MW. Existing oil and gas-fired steam boilers can rarely be converted to coal, for a variety of reasons. Many small powerplants, for example, are sited in metropolitan areas without space for coal facilities and without tolerance for new pollution.

Renewable energy sources and new, small-scale technologies are promising and often lend themselves more readily to use by small electric systems than by large systems. Publicly owned electric systems have been in the forefront of efforts to develop renewable or highly efficient power generating facilities, including central station solar power, biogas, geothermal, wood, municipal refuse, methane from garbage dumps, falling water at small existing and new dams, photovoltaics, and advanced heat engines. The Association has recently compiled a descriptive list, entitled "Public Power Innovations", of projects currently under way, and this list is attached to these comments. Many of the listed projects have been undertaken by small utilities.

Yet it does not follow that small utilities nationwide can now turn en masse to one or another alternative technology or renewable fuel. Such alternatives are likely to be practical only on a system-specific or site-specific basis. Many are experimental. As these are proven, many small utilities will adopt them because of their special suitability to dispersed small generation. But small utilities driven out of business in the coming decade by FUA will not be resurrected to put advanced technologies to work in the following decade. The willing laboratories these utilities could constitute for dispersed renewable and technologically advanced electrical generation in a citizen-governed utility framework will not exist.

Joint action efforts by two or more utilities to obtain economies of scale, among other benefits, have increased greatly in recent years and continue to hold promise for alternatives to dependence on small oil and gas-fired generating plants. In a typical joint action program, the participating utilities form a new public entity which has authority to issue revenue bonds in its own name and to finance all or part ownership of large generation and transmission systems, which in turn supply power to the member utilities of the agency. There are now 103 joint action projects and programs in the United States, more than double the number in 1973.

But joint action is not an automatic cure to the problems of small utilities. State legislation enabling the formation of joint action agencies must be obtained, and 20 states remain without enabling legislation. The current cost of money is a grave problem for joint action agencies; high interest rates not only increase future power costs, but also have blocked funding in states with interest rate ceilings, resulted in a deterioration of bond prices on outstanding issues, and caused commercial banks to decrease their purchases of municipal revenue bonds. The thrust of joint action projects has been toward construction of large base load power facilities, leaving peakload needs to be met by other means.

The problems all utilities face in finding new large power supply sources face joint action agencies too. The Municipal Energy Agency of Mississippi, a new joint action agency, has sought and thus far been unable to obtain power allocations from the Southeastern Power Administration, and is pursuing the possibility of installing low-head hydroelectric facilities at Mississippi dams, which, however, would meet only a minor part of the needs of the agency's members. Meanwhile, the municipal member systems continue to depend on oil or gas and continue to face FUA's cut-off of gas supplies.

Specific Problems Involving the Process for Obtaining Exemptions Under FUA

APPA commented in detail on problems of small utilities in obtaining exemptions under FUA in its comments of October 30, 1979, on ERA's Interim Rules. In addition, APPA's comments of March 12, 1979, on ERA's earlier Proposed Rules suggested that separate criteria be adopted for small utilities throughout the rules whenever their impact on small utilities would be disproportionately more severe than on large utilities. We continue to believe separate criteria to be essential in order to preserve the ability of small municipal systems to compete effectively with surrounding large privately owned electric utilities.

Federal Actions to Help Small Utilities Reduce Oil and Gas Dependence

Legislative amendments of FUA   Section 301(a) of the Act should be repealed. The prohibitions of current law force utilities to resort to scarce imported petroleum. The Act's preference for the use of imported petroleum over relatively abundant and less expensive domestic natural gas is irrational. Allowing electric utilities to use gas will not affect higher priority supplies, since under both Federal and State gas curtailment policy boiler fuel use is the first curtailed and the last served. Utilities receive gas only after all residential and commercial, and most other industrial requirements, are satisfied.

Changes in FUA Rules

1. ERA's cogeneration exemption rules should be revised. The showings required to demonstrate a "net oil and gas savings" to qualify for the cogeneration exemption would be a difficult burden for many small utilities. It is not clear what will constitute a sufficient demonstration that alternative units not yet constructed would otherwise (without construction of the cogeneration unit) be entitled to an exemption to use oil or gas; but if petitioners must meet the full evidentiary requirements imposed by the interim rules for exemptions for other alternative plants, then clearly many small utilities would have great difficulty in obtaining a cogeneration exemption. The problem would be multiplied for small utilities which have no present generation. Tracing oil

and gas savings through their supplier's system would in many cases be an impracticable task and would effectively put the cogeneration exemption beyond reach for these small systems. The General Accounting Office has suggested, in its Report to Congress on cogeneration, that industrial cogenerators be divided into "user classes," with small and medium size cogenerators exempted. We urge adoption of such an exemption for utility cogenerators as well.

2. Separate criteria and administrative requirements should be adopted for exemptions for small systems. Administrative procedures should be simplified, proofs required for exemptions should be made less difficult, and filing fees for exemptions should not be imposed.

Other Federal Actions, Policies, and Programs

1. Two barriers exist to the wider use of coal by wire to displace oil and gas-fired generation. One of these is an institutional barrier: intervening owners of transmission may not provide a uniform rate that permits sales to take place at an economic incentive to the seller and buyer. In some cases, access to transmission capacity is not available. The Administration should work to strengthen Federal authority to order wheeling of electricity. Without equitable access to transmission, small utilities are often barred from sharing the output of larger coal plants which could reduce their dependence on oil and gas.

The second restraint on greater use of coal by wire is the serious lack of sufficient high capacity transmission in some regions. The National Grid Study that was recently completed by DOE identified at least one such area -- the corridor between Florida and the mid-Atlantic coal generating area. There are other such areas: for example, it appears that greater amounts of hydroelectric power could be shipped from Canada to the Northeast and Midwest if ample transmission capacity were available. But until the transmission links are constructed, displacement of oil will be limited.

Increased transmission capacity would permit major transfers of excess energy which could be freed by load management carried out on a regional or inter-regional basis. The Public Utility Regulatory Policies Act of 1978 requires utilities to offer load management programs on a scale not previously common practice. The possibility exists that many more energy and capacity transfers could take place over the next decade if load management were integrated with transmission development.

2. Hydroelectric power offers a non-air-polluting, cost-effective, inflation-proof, non-oil-dependent source of energy. Water can be put to work quickly by developing small scale hydroelectric projects at existing private and public dams. There are about 50,000 dams in the United States. Many of them are untapped energy sources. The Administration has been slow to fund programs to stimulate non-Federal development, and has failed

to move aggressively to make water impoundments built and operated by the Federal government fully power productive.

The Administration has requested $10 million for Fiscal Year 1981 for small hydroelectric project feasibility studies under the program established by the Public Utility Regulatory Policies Act. No construction funds under the PURPA program were requested; the Administration says it will rely on the rural energy development program, combining authorities from seven different agencies to provide $300 million for loans and grants for construction of small hydroelectric facilities. Thus far, only one project has been funded under this program. Small hydro proponents, including APPA, have objected to the Administration's refusal to provide construction funds under the PURPA program.

3. Municipal solid waste can be used to help displace foreign oil instead of being buried in sanitary landfills. Waste fuel has its share of institutional, economic, and operational problems. What is needed is more Federal support for demonstrating the technology, financing feasibility studies, and stimulating community implementation. European countries now use garbage for significant amounts of power generation. The Administration should act to speed up our own application of their techniques and technology.

4. One of the great resources of the Department of Energy is the Federal power marketing agencies (PMAs) -- the Bonneville Power Administration, the Southwestern Power Administration, the

Western Area Power Administration, the Southeastern Power Administration, and the Alaska Power Administration. These agencies employ about 4,500 people, nearly 25 percent of the total number of DOE employees.

The PMAs currently market power from hydroelectric facilities. Significant national benefits, including benefits to small utilities, could be realized if the PMAs were authorized to integrate other types of renewable resource facilities into their systems. The PMAs could demonstrate the feasibility of operating such facilities within a utility system. For example, in predominantly hydroelectric systems like those operated by the PMAs, water can be stored when power from other renewable facilities, such as wind or solar, is available; thus the hydro base serves as a "storage battery" for power generated by other facilities. DOE should support legislation, recently introduced in Congress, authorizing the PMAs to purchase power from or construct renewable resource facilities, provided that the power is marketed under traditional marketing policies and the experimental costs of such technologies are subsidized by the Federal government.

5. DOE should encourage American application of the long-time European energy saving tactic: district heating. Today we have no real program that aids existing district heating, let alone new projects. In Minnesota, for instance, there are 14 municipal district heating systems located on the systems of publicly owned electric utilities. However, these systems face

difficulties in expending and achieving economic stability. As stated by the Minnesota Municipal Utilities Association, "It seems ludicrous that when the nation is spending millions on alternative energy resources and encouraging cogeneration in the private sector through tax incentives, that those operating cogeneration systems would be allowed to fail without a serious attempt to redevelop them and even expand them to make them economically and energy efficient." When confronted with the somewhat similar problem of rebuilding the nation's local sewage disposal plants, the Congress found that Federal aid in the form of matching capital grants was appropriate.

Submitted by

Ruth Gonze
Assistant Legislative Director
American Public Power Association
2600 Virginia Avenue, N.W.
Suite 212
Washington, D.C. 20037

Spencer Municipal Utilities
Box 110 • 712 N. Grand Avenue • Spencer, Iowa 51301
Phone 712-262-3027

SMU

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June 3, 1980

Small Systems Utility Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M. Street N.W.
Washington, D.C. 20461

To the Economic Regulatory Administration
in response to the request for comments on
the Fuel Use Act of 1978.

Spencer Municipal Utilities is located in Northwest Iowa and owns a 23 megawatt gas turbine. This unit operates on number one fuel oil. The unit is used as a peaking and an emergency unit. The unit was installed in 1970.

The F.U.A. of 1978 allows the Secretary of Energy to prohibit or restrict the use of petroleum in power plants. The act also allows the Secretary to issue exemptions to the rules.

The value and importance of the Spencer Municipal Utilites gas turbine unit is directly tied to an exemption. The conversion to alternate fuels is not cost effective due to the design. The operation as a peaking unit does not allow a base year for consumption allotments to be established.

It is important to this Utility that permanent exemptions are available and the process to receive such an exemption be relatively smooth and uncomplicated.

Joint-action base load power plant construction in Iowa is presently limited. Municipal Electric Utilities in Iowa cannot jointly finance without special legislation. The Iowa Senate this year passed legislation for joint action but it did not get through the Iowa House before adjournment. The passage of joint action legislation in Iowa could aid the construction of coal fired power plants in Iowa by Municipals and possibly remove petroleum or natural gas units from base load operation.

Very truly yours,

SPENCER MUNICIPAL UTILITIES

Leon J Rodas

Leon J. Rodas,
Assistant General Manager

LJR:bm

City of HOUMA

P. O. BOX 6097
HOUMA, LOUISIANA 70361
TELEPHONE 504-868-5050

June 4, 1980

Mr. Alan W. Starr
Division of Power Supply and Reliability
U.S. Department of Energy
2000 M. Street, N.W.
Washington, D.C. 20461

Dear Mr. Starr:

This letter is in response to your letter concerning problems with compliance of the Powerplant and Industrial Fuel Use Act of 1978 which small utilities are facing. We, the City of Houma, Louisiana have filed for a permanent exemption from the Fuel Use Act for our municipal electric system and feel our action will be typical for small utility systems throughout the country. Some of our problems may be isolated to South Louisiana utilities, while others may be a common problem for all small utilities.

I think it is important to first consider the evolution and future growth of the small power system before trying to establish any regulation. Our system started with small natural gas-fired diesel generators to meet the electrical needs of the people of Houma, Louisiana. Natural gas was the obvious choice for fuel since the City is located directly over natural gas fields. As the City continued to grow, so did the power plant by installing more and larger diesel generators. The last installation of diesels was three 4500KW units in 1958. Typical of many systems, in 1961, an 8,000 KW gas turbine was installed. Finally, during the 1970's capacity additions were of the size where the use of steam turbines was practical and three such units were installed during this time (12,500 KW, 26,000 KW, and 41,500 KW). The non-existance of a free-floating tie with any other utility requires a much greater than normal standby reserve capacity for our system.

From a management standpoint, the City Engineer was responsibile for the electric utility. He also handled gas, water, sewer, sanitation, drainage and other departments within the City. This could be done because the operation of diesels do not require much engineering involvement and many cities may still be at this point in their organization. The addition of steam units, system growth, and a greatly increased number of government regulations has caused us to reorganize and increase the size of our engineering staff. Major design modifications would probably have to be done by consulting firms due to the limited staff of our and other small utilities.

Converting to another fuel would be difficult for us for a new unit, not to mention conversion the existing units, if possible. Our powerplant was designed to burn natural gas and as a result there is very little on site space available for any type of fuel storage. The boiler design is simplified for natural gas firing and extensive modifications would have to be made even to burn oil.

The problems associated with burning coal for a small utility include delivery, maintenance of equipment, storage and questionable efficiency of the unit, just to name a few. While it can be stated these problems also exist for large utilities, the impact is not the same. A small utility does not have a large maintenance force which it can call on if needed. The bargaining power with coal suppliers and railroads would also be questionable for a utility with an annual consumption of 100,000 tons, based on problems the large utilities are having.

In conclusion, you stated in your letter that you were concerned by the lack of response by small utilities. In talking with people, I feel this may be due mostly to frustration or to rephrase it, "Why bother, what good will it do". There is a feeling of being caught in the middle with the D.O.E. saying don't burn gas or oil and at the same time the EPA is saying don't burn coal. I hope these comments will be useful. While they are mostly general comments, they do present significant problems to small utilities and may in fact jepordize their existence. Many small utilities may not have the funds or manpower available to become involved in hearings or court cases in order to get the necessary exemptions.

Yours truly,

John E Carlson Jr

John E. Carlson Jr.
City Electrical Engineer
City of Houma, Louisiana

JEC/mh

ORRVILLE MUNICIPAL UTILITIES

Electric, Water and Waste Treatment Systems

MUNICIPAL BUILDING • P. O. BOX 126 • ORRVILLE, OHIO 44667 • TELEPHONE 216/682-4976

ROBERT A. NICHOLS, *Director of Utilities*

June 6, 1980

Alan W. Starr
Division of Power Supply & Reliability
U.S. Dept. of Energy
2000 M Street, N.W.
Washington, D.C. 20461

Subject: Fuel Use Act

Dear Mr. Starr:

Although I wrote you April 1, 1980, after your May 21, 1980, correspondence I have read the attached copy of the Federal Register, dated Thursday, April 17, 1980, and wish to make additional comments.

The summary in this notice addresses systems with capacities of less than 2,000 MW, the indication being that such systems are considered "small". However, in the Background comments, I interpret the restrictions to cover generating units as small as 5 MW. The logic of this escapes me.

Orrville's system has peaked around 50 MW and we utilize two (2) units of over 20 MW to serve this load. If we burned something other than coal, we could be in big trouble because we probably could not afford to convert from another fuel to coal. In fact, we may experience a future problem because we have had occasion to use our alternate No. 2 fuel oil equipment when a pulverizer failed.

I hope any limits on natural gas or petroleum do not include that fuel used for ignition, start-up and flame stabilization. I would also hope that no restrictions on use of natural gas or petroleum as a prime fuel for existing units under 50 MW would apply because it would adversely affect our ability to serve our customers, usually at the most critical time of year (winter) when substantial damage could be caused by freezing. As stated previously, we have needed the use of our alternate fuel (No. 2 fuel oil) in the past, usually in the winter.

I recommend strongly that small utilities, utilizing existing units of 100 megawatts or less, be exempted from any restrictions on the use of natural gas or petroleum. This recommendation is based on the following.

1. Many such units were converted from coal to natural gas or petroleum at the request of various EPA's and/or their immediate predecessor.

2. Converting from coal to natural gas or petroleum fuel is relatively simple and inexpensive with some loss of efficiency. However, the converse is not true. Units previously converted were required to remove the coal handling and preparation facilities and most of the equipment was completely removed. Those units originally designed for natural gas and petroleum fuels are not easily susceptible to conversion and, considering the conservation to be achieved through the conversion of these relatively few units, would not be cost effective.

3. Some states, California in particular, have laws forbidding the use of coal for these units and the restrictions could not be applied equally to all utilities.

4. More gains could be made from the funds required for the conversion if the funds were applied to future units and other measures such as development of new methods and to conservation measures.

5. Most small utilities, if forced in the proposed manner, would have to increase their rates dramatically and would probably be forced out of the utility business as the financial burden could not be absorbed.

If our utility, and others like us, had more staff and more money, we could present our case much better. I hope that the end results of this process are more practical and reasonable than some of the previous programs.

We appreciate this opportunity to comment and we wish to thank you for your consideration and efforts.

Yours truly,

Robert A. Nichols
Director of Utilities

ds

CITY OF PRATT

Municipal Building
Pratt, Kansas 67124

June 3, 1980

Alan W. Starr,
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Washington, D.C. 20461

Dear Sir:

I find at our Power Plant, to follow your guide lines will cost our patrons an added burden. A small power plant cannot convert to coal and no large power company will sell a portion of their new coal fired plants because they know we will become a captive customer paying at a higher wholesale rate.

If we have to burn high priced imported oil to off set natural gas our production costs are increased five hundred percent. We serve in a agriculture area which by U.S. standards would be termed depressed, as our costs increase to our customers it places a unfair burden on them.

The FUA sets the years of 1974 - 1976 as the standards for the amount of gas to be used after 1990, as the worst years our plant could use as a standard. After the price of gas increased it caused more drilling for gas which increased supply also some large coal fired plants have been built relieving more gas for use.

I think all small power plants should be exempted with no exceptions.

Thank you,
Arlyn Bradford
Supt. Electric Department

Departments: Area Code: 316	Manager 672-5571	Clerk 672-6446	Electric 672-2022	Park 672-6882	Water 672-2111	Street 672-6101
	Airport 672-6842	Cemetery 672-3671	Police 672-5551	Inspection 672-3866	H & S 672-3866	

RUSTON UTILITIES SYSTEM

P.O. Box 280 Ruston, Louisiana 71270

AMERICAN PUBLIC POWER ASSOCIATION MEMBER

AWWA MEMBER

June 5, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and
Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Starr:

We realize that the Fuel Use Act is something that we need, but in Louisiana we will have to completely change our generation in the next ten years in order to comply with this Act because we have only gas and oil fired generation at this time.

Some of the municipalities joined together and formed the Louisiana Energy and Power Authority which we are hoping will enable us to buy some coal fired generation due to be available as early as 1981; however, this is putting a burden on us as far as capital costs.

We will need a little more gas for the next two years than we used in the years 1974 through 1977. By the end of the year 1986 we will be able to generate approximately 90% of our energy on coal and lignite. By 1990 we will, from all indications, be 100% coal and lignite or nuclear because gas and oil will be priced out of the kilowatt market.

Sincerely,

Max W. Albritton
Superintendent of Utilities

MWA/jr

CITY OF BURBANK
164 WEST MAGNOLIA BOULEVARD, P.O. BOX 631
BURBANK, CALIFORNIA 91503

PUBLIC SERVICE DEPARTMENT

June 5, 1980

Mr. Alan W. Starr, Chief
Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, DC 20461

Dear Mr. Starr:

Power Plant and Industrial Fuel Use Act (FUA) of 1978

In response to your letter of May 21, 1980, we would like to advise you that we are very concerned about our ability to comply with the guidelines established by FUA. We consider ourselves a small electric utility system with a present generating capacity of 250 MW. The generating capacity is composed of four operating steam turbine generators installed between 1949 and 1964 which are fired by either fuel oil or natural gas. In addition to these we have three gas turbines which are fired with either distillate fuel oil or natural gas and were placed into service between 1969 and 1975. None of these units are able to burn coal.

We have reviewed the possibility of converting some of these units to coal and find that, due to lack of space for storage, lack of railroad siding for delivery of coal, and for environmental reasons, it would be nearly impossible to get approval from regulatory agencies to install coal-burning equipment. Our future based load generation is planned to be new coal-fired power plants constructed outside of California with transmission lines for importing energy to Burbank.

We have contracts at the present time with the Eugene Water and Electric Board and the Weyerhauser Corporation to purchase energy from a wood-waste generation project in Eugene, Oregon. This is of short-term duration and not expected to be available after 1990. We are presently considering entering into a geothermal project being constructed in Imperial County, California; however, we feel this will represent less than five percent of our energy supplied by 1990.

We have seriously considered conversion of solid waste to methane for boiler fuel, windpower, and solar energy for future energy supplies. At best, we are expecting less than five percent from these resources by 1990. We have also been unable to identify more than 300 kW of cogeneration potential within the city at the present time.

It is our opinion that small utilities such as ours, with existing generating facilities, should be exempt from regulations which result in negative environmental impacts as well as excessively expensive and unreliable alternate energy supplies.

Sincerely,

Ronald O. Snyder
General Manager

ROS:JDW:j

cc: W. H. Fell, Glendale
K. A. Johnson, Pasadena
J. R. MacDougall

Board of Public Works

LIGHT WATER

CITY OF ZEELAND
MICHIGAN

June 4, 1980

Department of Energy
Washington, D.C. 20461
Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economics Regulatory Administration

Gentlemen:

Enclosed please find written comments from our consulting engineer and a few remarks from the writer. We are pleased that we are offered the opportunity to express our views, which might be of some value to you in your study.

The Board of Public Works, City of Zeeland has operated its Diesel Power Plant since 1934. We generate all of our own needs, with some power flowing out into our interchange pool during evening hours. We now have a capacity of 23 M.W. with a sub-station interchange transformer rated at 5 M.V.A. Zeeland exchanges power with the Wolverine Electric Cooperative. Our peaks occur at noon with Wolverine peaking in the evening. A new 6 M.W. dual-fuel diesel engine has just been added to our Plant, at a cost of 2.2 million dollars. The fuel cost of our plant this month was .03 cents per K.W.H. We feel that our ability to produce cheaper power for our own people plus the reliability we have is well worth the effort put forth. We operate our dual fuel units on natural gas and #2 fuel oil. We have an interruptable gas rate, but our interruptions are few and far between. Our generation is about 98% on natural gas with about 7% pilot oil. Our plant houses nine engines.

We feel that a direct hardship would result if we lost our gas and oil for our internal combustion engines. Our Plant would be forced to shut down with our large investment lost. All power would have to be purchased, at a far greater cost. Electric rates would have to be increased, adding to our continued spiralling cost of living. The residential and industrial revenue produces about $300,000.00 per month and a net to surplus profit of approximately $600,000.00 to $800,000.00 per year, to be used for future expansion. Twenty people depend on us for their livelihood.

Thanking you again for this opportunity to express our views.

Very truly yours,

Martin J. Hieftje

Martin J. Hieftje
Manager of Utilities

/Enclosure

J. BRYAN SIMS & ASSOCIATES
CONSULTING ENGINEERS
GRAND HAVEN, MICH. 49417

MEMBER OF
I. E. E. E. AND A. S. M. E.

P. O. BOX 225
302 S. BEECHTREE
TELEPHONE (616) 842-7660

June 3, 1980

Mr. M.J. Hieftje, Manager
Board of Public Works
City of Zeeland
Zeeland, Michigan 49464

Dear Mr. Hieftje:

Subject: Inquiry from D.O.E.

You have asked me to look over the inquiry of Mr. Alan W. Starr, Chief of Science Technology of the Department of Energy, Washington, DC concerning information which might be helpful in possible modification of the Fuel Administration Act of 1978 (F.U.A.) particularly as it effects smaller electric utilities.

Having been actively engaged in engineering of relatively small electric generating plants since the early twenties, when I had occasion to observe and study one of the early lignite coal burning plants in Texas, and later noted with interest the transition from coal burning to rapid use of oil and gas fuel in an area noted for petroleum potential, the present situation is indeed perplexing.

I am sure that we engineers were then aware that oil and gas were, generally speaking, a refined type of fuel compared with coal (possibly with the exception of heavy residual) which might not always be most economical, but at least at the time it was, particularly when capital costs were involved and the lack of available hard coal in the area.

Hence, it has been very interesting to observe during recent years, the efforts to control fuel use by legislature action. As with all such controls, it is understandable that unforeseen conditions would necessitate some rule modification changes periodically.

It is with the above thoughts in mind that we offer the following comments and/or suggestions in response to paragraph 1 and 7 inclusive as per the "Request for information" with emphasis on this geographic area.

1. Our observation in general would be that there is a need for closer

practical coordination and agreement between the various governmental agencies themselves including Federal and State.

Broad legislative control is historically new in this field and this has undoubtedly required new organizations of enforcing personnel. Some members may or may not have had the expertise nor the experience in interpreting the rulings and guidelines, and this in itself may delay and confuse the power plant builder and his engineers, thus adding to unnecessary cost of the project. Recent excessive inflation costs are burden enough without delays caused by indecision, inflexability, sometimes impractical personal opinions, if not dictoral interpretation, by various members of enforcing personnel.

2. By necessity and actual desire to be loyal citizens, most power plant builders of their own volition will switch from less "presently considered scarce" fuels to others where it does not present excessive hardship. Thus, sympathetic understanding with pratical approach by enforcement personnel will accomplish the objective and ultimate goal.

   Obviously as indicated, the smaller utilities with limited diversified reserves are likely to be placed in more difficult position, often with one source of fuel.

   Rapidly by their own efforts, the smaller utilities are interconnecting to help provide diversity and assistance to help peaks and emergencies of their neighbors, large or small.

3. Due to the energy situation, some of the smaller plants, again of their own accord, have been experimenting with alternate fuels i.e., wood, etc. Two of these in Michigan are: Grand Haven and St. Louis. There is also a genuine interest in rehabilitation of many previously abandoned lowhead hydro electric plants.

   The majority of these hydro plants were abandoned due to availability of power from large central stations generating large quanities at increasing higher temperatures, with an abundance of their self selected fuel sources and with resulting lower initial capital costs. It is notable however, that the large central stations have more recently experienced many new problems including limitations on type of fuel supply, the flattening out of efficiency due to limits of temperatures, excessive capital costs and many other changes. Hence, the restoration of these hydros with the potential of substantial total capacity may be received with more sympathy than previously. It is interesting to note that numbers of the small hydros were actually owned by the larger systems themselves.

   The City of Sturgis, Michigan is now renovating their hydro with more efficient equipment in addition to increasing capacity with 6,000 KW diesel fuel diesel standby. It was interesting to note that their engineers recently reported that "it only took six months to obtain government authority or permits".

It is our hope that governmental authorities in their quest to improve the fuel situation will keep in mind that during recent world wars much of the war strategy was to bomb the larger central stations and that the smaller geographically separated power sources could help prevent a complete paralysis of our nation.

In considering other sources of energy, much has been said about wind power, solar energy, etc. Our recent inspection of a 150 KW generating plant by solar energy recently completed, indicated a cost of over four million dollars which, although an admirable effort indicated that it is not too promising in the near future. Most immediate solar results will be the use for building heating. Michigan is not blessed with sunshine, but architects are aware of its potential and are beginning to take advantage of it.

4. Cogeneration has gone through cycles over the years. A few decades ago, more chemical plants, steel mills and other firms requiring quantities of steam and power actually produced more of their power than has been the case during recent years when many of them for one reason or another have less inclined to generate part of their requirements. Many times the larger utilities were inclined to discourage this cogeneration. However, it would appear that this cogeneration does have potential and should encourage further study. As as example, the writer recently was requested to make a tenative study of a chemical plant discharging 90°F superheat steam in sufficient quantity to run a 3,000 KW turbo-generator which in terms of purchased power would amortize its cost in three years providing cogeneration could be negotiated. We understand this is up for further study.

5. & 6. Referring further to cogeneration, many smaller municipal electric generating plants have, in the past, experienced some difficulty in consummation of interconnections and cogeneration, often due to competitive reasons. Our experience however is that there has been some improvement in this situation in the Michigan area, but competition being natural, it occasionally can be detected in negotiations.

The importance of improving load factors has always been known but never been appreciated as much as under todays conditions! This can be supplemented by continuity of service. For example, during an icy blizzard when coal handling equipment failed in some of the larger plants, Zeeland, Michigan with numerous dual fuel diesels was urged to pump all power possible back into the interconnecting transmission system.

The usefulness of this type of highly efficient, quickly available, dual fuel power must be appreciated by the Department of Energy, whose cooperation has enabled the Zeeland plant to continue operation. Many larger utilities have previously installed gas-oil fired turbines for emergencies, but from our own previous actual studies, the turbines are not any-where near as efficient as the modern high thermal efficient dual fuel diesel. We see a constructive need for the highly efficient dual fuel diesel units in the immediate near future where applicable. Many situations allow them to use interruptable gas and thus improve the load factor on gas systems. Few diesels are operating solely on fuel oil in this area, but some of the older nondual fuel units are retained for emergencies.

7. Unfortunately, due to the late assignment, I have not had the opportunity to make any suggestions for any changes as requested in Items 7-I, II, III, IV, and V as I have not reviewed the F.U.A. administrative procedures, rules, amendments to the fuel use, other actions, etc. However, I shall be glad to do if requested.

Attached is some background information which may have had some influence upon the above comments and observations.

Respectfully submitted,

J.B. Sims, P.E.

Enclosures

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 305/423-9100

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CURTIS H. STANTON
Executive Vice President & General Manager

J. THOMAS GURNEY, SR
General Counsel
P. O. Box 1273
Orlando, FL 32802
305/843-9500

June 5, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy, Room 4002
2000 M Street N.W.
Washington, D.C. 20461

Gentlemen:

This is in response to the Department of Energy's request for information concerning the problems of small electric utility systems in complying with the Powerplant and Industrial Fuel Use Act of 1978 as published in the Federal Register, Volume 45, No. 76 on Thursday, April 17, 1980 and are the comments of the Orlando Utilities Commission.

The Orlando Utilities Commission (the Commission) is a municipally owned and operated electric and water utility providing electric and water service to the City of Orlando and contiguous areas with an overall electric service area of 200 square miles with approximately 84,000 metered electric services. With the exception of approximately 13 MW of nuclear capacity from Florida Power Corporation's Crystal River #3, all the generating facilities of the Commission are located in Orange County and Brevard County, Florida. The system summer net generating capacity is 726 MW. All of this generating capacity utilizes natural gas or oil. Approximately 30 MW of the aforesaid capacity is generated by combustion turbines which use distillate oil or gas and the remainder consists of steam units which use number 6 oil or gas.

The major problem created by the Fuel Use Act for the Commission is the selection of the various alternatives provided for in the act with respect to the system compliance option and/or permanent exemptions for existing plants. The 1974-1976 base period represents a period when the Commission was deeply curtailed by its supplier, Florida Gas Transmission Company. In contrast, the larger power systems in the state received substantial quantities of gas during this base period.

This was due to their purchase arrangements and transmission agreements with Florida Gas Transmission Company. If Florida Gas Transmission has adequate gas supplies available in the future and the Commission were limited to quantities determined by the base period use, the large power systems in Florida would receive a disproportionate amount of gas to the disadvantage of the Commission. Without the provisions of the Act, the Commission would receive its proper allocation under its contractual agreement with Florida Gas Transmission Company.

An indepth study that would be necessary in order to make a prudent judgment on which of the various alternatives to take, taxes the manpower resources of the Commission. Contracting for such a study imposes a much more economic burden to the small utility than to the large systems which have the expertise and personnel internally to conduct such studies. The selection of an alternate based on inadequate information could result in additional fuel costs in the millions of dollars and would be paid by the customers of the Commission.

In order for the small utility to avail themselves of alternate fuels, such as coal and nuclear, they must involve others in such undertakings. The small utility alone cannot generate the large capital necessary to finance coal or nuclear power plants. The municipally owned utility systems would be in a better position to organize and attract interest in such projects by the private segment of the industry if some of the restrictions with regard to the tax exempt status of revenue bonds for such use were removed. The removal or mitigation of some of these restrictions would extend the flexibility available to the small municipal utility in developing their contractual agreements with participants from the privately owned utilities. This is not the result of the Fuel Use Act but comes under Item 7 (IV) in the Request for Information section of the published notice.

In summary, all of the generating facilities of the Commission at the present time, with the exception of the 13 MW nuclear capacity, are combination oil and gas fired units. Imposing restrictions on the use of natural gas limits the fuel flexibility options available during the remaining life of the units. Selection of an alternate under the act may result in actions contrary to the interest of the electric consumer of the Commission. More flexibility in financing arrangements by the elimination of some of the present restrictions on the tax exempt status of municipal bonds, would enhance the ability of the Commission to attract others in coal and nuclear projects, thereby making alternate fuel sources available as viable options. In the short term, the most effective action would be the elimination of the Act's restrictions on burning natural gas in existing power plants. The burning of such gas to conform to the curtailment priorities established by the appropriate regulatory agency.

Yours very truly,

ORLANDO UTILITIES COMMISSION

Louis E. Stone

Louis E. Stone, Manager
Electric Operations

LES:sw

LINCOLN ELECTRIC SYSTEM LES
CITIZEN-OWNED

1200 "N" STREET, SUITE 300 · P. O. BOX 80869 · LINCOLN, NEBRASKA 68501 · TELEPHONE 402-475-4211

June 5, 1980

Mr. Alan W. Starr
Division of Power Supply and Reliability
U.S. Department of Energy
2000 M Street N.W.
Washington, D.C. 20461

Dear Mr. Starr:

Thank you for providing a forum in which I can express our concerns on the impact of the Fuel Use Act on small electric utilities such as Lincoln Electric System (LES).

LES is the municipally-owned electric system of the City of Lincoln, Nebraska. At the present time, LES supplies electric energy to some 77,100 customers within the corporate limits of the City of Lincoln and adjacent territory. The service area covers about 190 square miles of which about 58 square miles is within the City limits. Estimated population in the service area is about 195,000 of which about 180,000 is within the City limits.

LES is in compliance with all aspects of the FUA. The present LES fuel mix is as follows:

Nuclear	31%
Coal	22%
Hydro	7%
Purchases	38%
Oil & Gas	2%

LES is a summer peaking utility. The Lincoln, Nebraska economy is primarily based upon agriculture, light industry and service. This base economy combined with a high air conditioning load in the summer results in a poor load factor, and a heavy dependence on peaking resources such as combustion turbines and short term economy energy purchases from the Mid-Continent Area Power Pool (MAPP).

Attached please find LES' comments to your request for information.

Sincerely,

Julian J. Brix
Manager
Power Supply

JJB/bd

Attachment

I. Impact of FUA on LES

A. Development Plans

1. FUA regulatory impediments to new combined cycle plants (40% efficiency) forced a recommendation in the latest LES Power Supply Plan to install multiple simple cycle combustion turbines (26% efficiency) which could be operated to meet the requirements of the regulations. The result is that under identical loading regimens, the recommended option (simple cycle) will consume more oil than the preferred option (combined cycle). This otherwise unnecessary increase in oil consumption will, of course, be borne by consumers in the form of higher electric rates and add to the Nation's deficit of payments problem.

   The compliance strategy is to continue to make maximum use of Mid-Continent Area Power Pool (MAPP) benefits to reduce oil and gas consumption, and to install and license multiple simple cycle gas turbines as needed for peaking and emergency service.

II. Technical and Financial Feasibility of Using Coal

A. Technical

1. FUA has no impact on LES' ability (or non-ability) to use coal. One LES facility, the K Street Plant, was originally built to burn oil, gas or coal. However, EPA ordered the Unit off coal in early to mid-seventies. The plant was built for a different era. There is no space at its site which is available for scrubbers and other pollution control devices. As a result, the Unit burns oil and/or gas when it is operating. (The plant is normally idle as a cold-standby reserves plant.)

   There is no compliance FUA strategy for this problem since LES already complies with the FUA.

B. Financial

1. The FUA has little effect upon financial feasibility of using coal.

   The financial feasibility of using coal becomes a question of capital and operating expense of using coal versus the capital and operating expense of other alternatives. As a result, in many cases small utilities must join together to implement larger power projects in order to realize the benefits of economy of scale of capital, operating and regulatory expense.

Compliance strategy would include access to participation power projects which are large enough to economically make use of unit train coal deliveries, etc.

III. Experience in Unusual Fuels and Technology

A. Unusual Fuels

1. 1977 investigation of coal/RDF mixture in a generation plant to be built near Lincoln in late 1980's. No FUA benefit or impact. No compliance strategy.

2. 1980 Municipal Solid Waste Plant Feasibility Study in progress to determine the financial viability of building a local cogeneration facility which burns 100% municipal solid wastes as fuel. No FUA benefit or impact. No compliance strategy.

B. Unusual Technologies

1. Small scale wind energy conversion system demonstration project. No FUA impact or benefit. No compliance strategy. Interconnection research will be used in PURPA related work.

2. Literature investigation of fuel cells, fluidized bed combustion, coal gasification and compressed air storage. No FUA benefits or impacts.

   Compliance strategy - may invest in any of these technologies if they are proven to be financially, technologically and environmentally attractive.

IV. Attempts to Develop Cogeneration

A. Municipal Solid Waste Cogeneration Plant

1. No FUA benefits or impacts. Plant is under investigation and must be economically viable in its own right in order to secure market for steam.

   Compliance strategy - implement the plant if it appears to be financially, socially and environmentally feasible.

B. Northern Natural Gas-Cogeneration Project

1. Partially financed by DOE research grant, results will be used in PURPA related matters. No FUA benefits or impacts.

C. Saint Elizabeth Hospital Cogeneration Project

1. Partially financed by DOE research grant, results will be used in PURPA related matters. No FUA benefits or impacts.

V. Specific Problems in Obtaining Exemptions

A. Exemption to Use Natural Gas in Existing Combustion Turbine

1. LES is currently engaged in a project to reimplement the natural gas capabilities of one of the two combustion turbine peaking units in the LES resource mix. The anticipated benefits of the project exceed the costs by a factor of six over the anticipated five-year period of the exemption. In addition, the availability of gas as a fuel would allow LES to use its stocks of #2 distillate as a strategic mini-reserve for public transportation and agricultural purposes. (LES established such a precedent during the 1979 fuel shortages which followed the Iranian Revolution.)

The FUA prohibits LES from using gas in the turbine unless an exemption for such use is obtained. Two exemption types were considered: (1) Public Interest Exemption and (2) Peakload Powerplant Exemption.

LES petitioned the ERA on January 18, 1980 for the Special Temporary Public Interest Exemption.

The ERA decided to process petitions for the Special Temporary Public Interest Exemption in groups - thereby causing an unnecessary increment of delay in the exemption process. The LES Petition was finally published in the March 21, 1980 Federal Register along with 167 other petitions.

A mandatory 45-day public comment period for the March 21, 1980 group ended on May 5, 1980. On the final day for comments, a consortium of alleged process gas users requested a public hearing on the entire March 21 list of Special Temporary Public Interest Exemption Petitions. Telephone checks with the ERA revealed that a public hearing notice must be published in the Federal Register at least 30 to 45 days prior to the hearing.

Even though a month has passed since the close of the public comment period, the ERA has yet to set a public hearing date.

This regulatory delay is adversely impacting LES.

First, the reimplementation of the combustion turbine's gas capabilities require that a compressor be purchased and installed to boost the present gas delivery pressure (which is locally available at the gas turbine) to turbine requirements. The unnecessary ERA delays are impacting construction and equipment acquisition schedules, and allowing equipment prices to escalate. Second, LES makes heavy use of MAPP Schedule E (Economy Energy) purchases to reduce dependence upon #2 distillate oil. The price of a Schedule E transaction is defined as the average of the supplier's incremental and the purchaser's decremental cost. The LES decremental cost of burning #2 distillate valued at current replacement price is about $85/MWh. The projected LES decremental cost based upon burning natural gas valued at current replacement price plus an additional 20 percent escalation would be about $44/MWh. Assuming a typical $15/MWh MAPP region incremenal cost, the LES Schedule E purchase price would be about $50/MWh when based upon an oil decremental cost and about $30/MWh when based upon a gas decremental cost. Based upon these prices, the cost of purchasing 25 MW of Schedule E for one hour would be $750 for the gas based decrement and $1250 for the oil based decrement. These $500 per hour savings accrue even when the turbine is not running - when no gas or oil is actually being used.

Finally, Cooper Nuclear Station, the LES nuclear resource, is expected to have an extended outage in March or April 1981 for refueling and turbine rotor replacement. It was our hope to have lower cost gas available to the peaking unit should it become necessary to run it during such capacity outages. (It would become necessary to run the peaker if short term capacity is not available within MAPP.) Instead, regulatory delay is forcing LES into the spectre of possibly using excessive amounts of #2 distillate oil when a more economic alternative, gas, would otherwise be available at one third the price of distillate.

B. Peakload Powerplant

1. To qualify for permanent peakload exemption, a utility must certify to the ERA that the powerplant will be operated solely as a peakload powerplant, and that a denial of the exemption would increase the loss of load probability for the appropriate ERA defined electric region to greater than one day in five years.

The ERA electric region for LES is the area covered by the Mid-Continent Area Power Pool (MAPP).

This regional approach ignores existing contractual requirements as well as transmission limitations. A definition that would be more representative of such constraints should be strived for.

VI. Access to Large Powerplants

No FUA impacts. LES is presently participating in a 670 MW nuclear plant in Nebraska and a 1500 MW mine mouth plant in Wyoming. In addition, it has obtained short term firm power from the 650 MW Nebraska City steam-electric plant.

VII. Possible Federal Actions That Could Help Small Utilities

A. Change in FUA Administrative Procedures

1. Work to eliminate the excessive bureaucratic delays which seem to plague the ERA.
2. Eliminate national review of petitions for exemption and implement a regional review. Include a requirement that a commenter must have standing within the region of the utility affected by his comments.

B. Legislative Amendments to the FUA

1. Eliminate the reliability requirement for permanent peakload exemption for existing powerplants.
2. Allow peaking units to use any combination of natural gas or oil with no proportionality restrictions.

C. Other Federal Actions, Policies or Programs

1. Take action to ensure competition between coal haulers. Such action could include the granting of eminent domain to slurry pipeline companies.
2. Reduce the maze of permits which are required to build energy facilities or to open coal mines. Reduce the regulatory load imposed on industry to free engineers for productive work. (Staff and budget limitations make it nearly impossible to keep abreast of laws, reports and regulations.)

Gainesville
Alachua County
Regional Electric
Water & Sewer
Utilities Board

Progress
Through
Cooperation

June 6, 1980

Mr. Alan W. Starr
Small Utilities Study
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Room 4002, 2000 M Street, N.W.
Washington, D.C. 20461

Subject: Problems of Small Utility Systems Complying with the Fuel Use Act

Dear Mr. Starr:

This letter is in response to the Department of Energy's request for information and comments concerning the problems that small utilities face in complying with the Power Plant and Industrial Fuel Use Act. I would like to point out that these comments are in addition to and supplement those comments made by our attorney, Mr. Alan Roth, with Spiegel & McDiarmid, who has made comments on behalf of eight of the municipally owned systems here in the state of Florida.

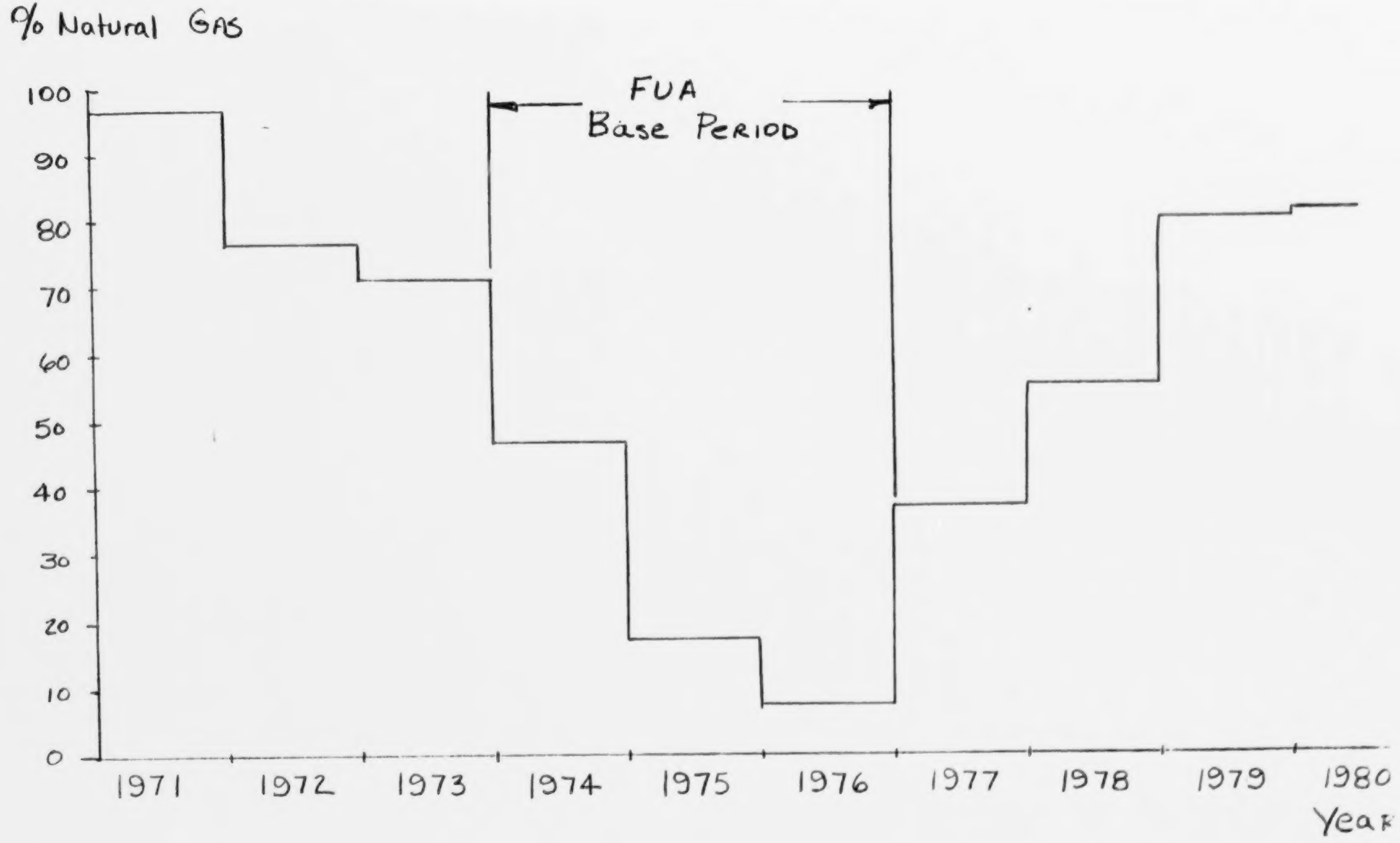
The City of Gainesville is a municipally owned and operated utility system and presently has 245 MW of gas and oil fired generating capacity. In addition, the City owns an 11.6 MW share of Florida Power Corporation's Crystal River 3 unit and also expects to bring on line its Deerhaven 2 plant, a 235 MW coal fired unit in the first quarter of 1981. The system currently serves approximately 41,000 customers in the Gainesville urban area.

The City of Gainesville certainly supports the three major purposes of the Fuel Use Act which are to 1) reduce the importation of petroleum, 2) conserve natural gas for higher uses than the generation of electricity, and 3) increase the use of the nation's indigenous energy resources such as coal. It is Gainesville's opinion, however, that these purposes of the Fuel Use Act should be met by the utility industry as a whole and that the cost associated with such regulation should not be disproportionately borne by small utilities in specific geographical areas. The plain facts are that small municipal utilities across the United States are struggling for survival in the face of unfair competition from investor owned utilities. The situation in Florida is not unique. As I'm sure you know, the cost of fuel today represents some 40 to 50 percent of the cost to generate electricity. Consequently, municipal utilities are most concerned about the cost of fuel in their efforts to remain in a competitive posture with investor owned utilities.

The Power Plant and Industrial Fuel Use Act has taken on the ominous distinction of being the single most significant piece of legislation in terms of its potential impact on the cost of generating electricity for small municipal utilities in the state of Florida. For example, Gainesville, in carrying out planning studies early this year, prior to receiving exemptions on its steam units, concluded that for the 12 month period ending December 1980, that the utility system's fuel cost would increase some $8.2 million, or 37% if those Public Interest Exemptions were denied. This translates into approxiamtely an $8.83 increase on the monthly bill of the average residential customer, or an increase of approximately 16.8%. Clearly, restrictions placed on the utility system's ability to burn natural gas after the exemptions have expired and prior to 1990 will have a significant impact on this utility's competitive posture as compared to other utilities in the state of Florida. Such increases will have the effect on the City of Gainesville of moving its cost of electricity from what would be considered average in the state of Florida to a cost that would be considered in the high range.

As has been pointed out to the Department of Energy on many different occasions, the most significant burden placed on the municipal utilities in the state of Florida is due to the base period, 1974-1976, on which the restricted use of natural gas is based for the years prior to 1990. As can be seen on the attached graph, the 1974-1976 base years for calculating Title III FUA permissible levels of natural gas consumption were years of abnormally low gas use for this utility. The proportion of natural gas burned by the City of Gainesville was at an all time low during the year 1976 when only approximately 7.5% of the fuel burned was natural gas. This compares to 96.3% natural gas which the City burned in 1971 and 80.2% which the City has burned this year to date under the Public Interest Exemptions. It should be noted that the 80.2% has occurred even through that portion of the year which contains the winter months January through Feburary in which the utility experiences its maximum curtailment. The average proportion of gas burned during the FUA base period 1974-1976 was 23.6% on a systemwide basis, which is significantly below present gas availability.

The circumstances of the steep curtailment to Florida municipal utilities in the 1974-1976 base years has been the subject of litigation in the past and is now the subject of a special investigation by the Federal Energy Regulation Commission, Docket No. IN78-2. On August 21, 1978, FERC issued an order rejecting settlement and directing its Office of Enforcement to institute an investigation in the case of Florida Gas Transmission Company, Docket No. CP74-192. The City of Gainesville, along with seven other cities, entered into a settlement agreement and



Gainesville Regional Utilities
Percent Natural Gas Burned 1971-1980

general mutual release with Florida Gas Transmission Company and with Amoco Production Company, dated July 12, 1977. The settlement agreement with Florida Gas and Amoco amounted to some $18 million which represented settlement of the litigation which the cities had brought against Florida Gas and Amoco with regard to the steep curtailment of natural gas delivery.

It should be pointed out that the two major investor owned utilities in the state of Florida, Florida Power & Light Company and Florida Power Corporation, were receiving gas from Florida Gas Transmission Company as pipeline transmission customers and consequently were not steeply curtailed during this same FUA base period of 1974-1976. Consequently, with the expiration of Public Interest Exemptions which is scheduled for fall of 1981, Florida Gas Transmission Company will have significant amounts of natural gas available for the generation of electricity. Since, due to the abnormally low gas burn which the City saw in the 1974-1976 base period, Gainesville will be severely (23.6%) restricted by the Fuel Use Act from burning the gas after the expiration of its Public Interest Exemptions. Florida Gas will have the opportunity to market the gas to the investor owned utilities in the state which are not constrained by the unfortunate base period. The competitive effect of such a shift in natural gas supply requires no further discussion.

In addition to the problems caused by the selection of the base period for the Title III restrictions, the selection of a 1976 base period as relates to the Compliance Option is also most unfortunate. For example, during 1976 approximately 7.5% of the fossil fuel burned by Gainesville was natural gas. Since the System Compliance Option restricts gas burns after January 1, 1990, to 20% of the utility's base period usage of natural gas, Gainesville will be almost entirely precluded from burning natural gas post 1990 under the Compliance Option. Clearly any incentives to negotiate a Compliance Option with the Department of Energy would only lie with the increased availability of gas prior to 1990. In view of the stiff requirement of giving up any accessibility to permanent and temporary exemptions under Title I, coupled together with the severe restrictions on gas burned post 1990, it becomes questionable whether cities like Gainesville should bother to negotiate a Compliance Option.

The requirement that a utility give up any right to exemptions under Title III of the Fuel Use Act if a Compliance Plan is approved is an incredible requirement. It is especially disconcerting to think that a utility which successfully negotiates a Compliance Plan with the Department of Energy would give up exemptions which would allow it to promote cogeneration or to burn certain fuel mixtures containing natural gas or petroleum, especially when these exemptions would ultimately allow the utility to comply with the major purposes of the Fuel Use Act to conserve natural gas and to reduce the importation of foreign fuel oil. It is very unlikely that a small utility would be in a position by August 1981 to completely close the door to cogeneration or fuel mixtures through the year 2000. To the extent that it is already in the nation's interest to first promote the reduction of importing foreign fuel oil in the near future, the rationale of forcing a small municipal utility into a position of negotiating a Compliance Plan which would give up any entitlement to Title III exemptions, is most distressing. In order to promote the reduction of importing foreign fuel oil in the near future, Gainesville recommends that the Act be amended to provide for longer term public interest exemptions.

In addition to the obvious competitive impacts that the Fuel Use Act has on small municipal utilities, the regulatory burden likewise is disproportionally burdensome on smaller utilities. The City of Gainesville estimates that during the current year that it will have to expend in excess of one half of a man year to respond to the requirements of the Fuel Use Act. These activities include such items as additional computer simulations of power plant fuel consumptions, monthly filing of ERA 160 forms, semiannual reports in compliance of Public Interest Exemptions, the filing of Public Interest Exemptions, meetings with the Department of Energy, the filing of a conservation plan as required by the Public Interest Exemption, and the possible negotiation of a Compliance Option.

With regard to the filing of the conservation plan as required by the utility's Public Interest Exemption, one very serious observation should be made. The Department of Energy has notified the utilities who have received Public Interest Exemptions that they must file conservation plans which deal with such issues as power plant productivity and residential and commercial conservation programs. Although the National Energy Conservation Act of 1978 only applies to larger utilities, the Department of Energy has suggested that the minimum DOE standards for an acceptable residential energy conservation program are established by Part I of Title II of the National Energy Conservation Policy Act. The Department of Energy has used its position of having absolute say-so over the municipal utilities' access to natural gas, which they desperately need to remain competitive, as a lever to force small municipal utilities to abide by the NECPA energy conservation requirements even though the law only applies to larger utilities and exempts smaller utilities.

The Fuel Use Act is a nightmare for small municipal utilities. In the state of Florida the utility industry, especially the small systems, depends highly on oil and gas fired generation. It should be noted that all of the coal fired generation in the state and most of the nuclear generation is presently owned by large investor owned utilities. In the near future two of the major purposes of the Fuel Use Act to reduce importation of fuel oil and the conservation of natural gas are in direct conflict in Florida. The Department of Energy should recognize the reality of this difficulty within the state of Florida and place priority on allowing utilities to burn as much natural gas as available with the result being significant reduction in the importing of foreign fuel oil for generating electricity in Florida. For example, the Public Interest Exemptions for Gainesville allowed this system to displace 510,000 barrels of oil for the six month period ending December 31, 1979. In addition, the Department of Energy should recognize the disproportionate burden placed on small municipal utilities in the state of Florida due to the unique circumstances associated with the 1974-1976 base years and the curtailment inflicted upon the utilities in Florida during that time period. The municipal systems in Florida are significantly disadvantaged by the Fuel Use Act, more so than the large investor owned utilities due to the fact that the municipal utility systems have a higher proportion of oil/gas fired generating capacity. Consequently they are more vulnerable to the Act's prohibitions and restrictions on gas firing in existing power plants.

Gainesville notes that the Carter Administration's Regulatory Analysis Review Group has concluded that the Fuel Use Act will yield much smaller oil and gas savings than had been expected and that the Department of Energy should consider either easing or terminating its Fuel Use Act rules and regulatory program. The Review Group also concluded that sharply rising oil prices will cause utilities to rapidly abandon oil and gas on their own and therefore any FUA related gains will be small. Gainesville concurs with the opinion of the Regulatory Analysis Review Group. Based on its own projections on the cost of electricity to be generated from its new 235 MW coal fired power plant, Gainesville has concluded that the price per KWH will be less than that which could have been generated from a similar size oil fired unit. In view of the cost pressures caused by sharp increases by the oil exporting countries, the uncertainty of fuel supply (Gainesville's oil supplier, Amerada Hess notified it shortly after the Iran development that oil deliveries would be sharply reduced during the month of March, 1980.), the utility industry will, as a whole, be looking to energy resources other than natural gas and oil. In view of these facts, and in view of the heavy burden that gas burning restrictions will cause on Florida municipal utilities with respect to existing units, it is Gainesville's recommendation that the Act restrictions on gas in existing power plants be eliminated.

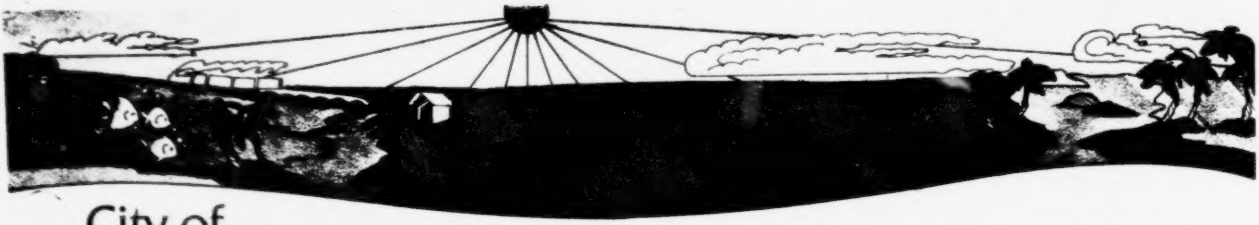
Respectfully submitted,

Richard L Hester

R. L. Hester
Deputy City Manager for Utilities

RLH:JW:kv

cc: Jerry Warren
Alan Roth



City of
Homestead, Florida 790 HOMESTEAD BOULEVARD, HOMESTEAD, FLORIDA 33030 (305) 247-1801

June 5, 1980

Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
U. S. Department of Energy
2000 M Street, Northwest
Washington, D. C. 20461

Reference: Your Letter Dated May 21, 1980, Our File 7002-141

Dear Mr. Starr:

Previous comments which the City of Homestead and their Consultants have submitted in reference to the Power Plant and Industrial Fuel Use Act of 1978 have specifically addressed the problems of small utilities.

One of the main problems that we have is with the Department's definition that a small utility is a utility with a generating capacity of 2,000 megawatts or less.

By the standards of the City of Homestead and many other utilities in the same circumstances as Homestead, an electric system with a total generating capacity of 2,000 megawatts, or even substantially less than 2,000 megawatts, would still be a very large system. By the standards of the City of Homestead, a "small" system would be a system with a generating capacity of 150, or possibly even 200 megawatts or less - one-tenth the size that has been chosen by the Department of Energy to establish the criteria for small systems.

We understand that there must be a cutoff somewhere, but it is strongly recommended that the Department of Energy give particular recognition to the very special problems of these utilities, those with a generating capacity of 200 megawatts or less. It is recognized that the problems of systems of 2,000 megawatts or less, generated by the Power Plant and Industrial Fuel Use Act of 1978, and the burgeoning number of other regulatory requirements at both State

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and Federal levels is significant. The problems faced by utilities of 200 megawatts or less, which hereafter will be called "very small" utilities, are, in comparison, overwhelming.

IT IS BELIEVED THAT THE BEST WAY THE DEPARTMENTS OF ENERGY AND CONGRESS COULD RELIEVE THE PROBLEMS OF THE VERY SMALL (200 MEGAWATTS OR LESS) UTILITIES WOULD BE TO TOTALLY EXCLUDE THEM FROM APPLICATION OF THE FUEL USE ACT OF 1978.

It is strongly recommended that the interest of maintaining competition, optimized use of capital and energy resources - in fact, the total implementation of the National goals with regard to the Energy Program - would best be served if the Department of Energy could concentrate on the overall program without the necessity of the detailed involvement of these very small utilities. From the standpoint of the utilities, it would simplify their operation, lower their administrative cost, and to this extend, promote the interests of the national economy and their local customers.

I do not have available to me the statistics that would be necessary to complete the evaluation which I am about to make; I am sure that you do. If the generation capacity and the energy production of all of the systems with a generating capacity of 200 megawatts or less were totaled, I believe that the percentage of the Nation's total electrical energy production would be even smaller if plants that use diesel engines as prime movers - facilities which are already excluded from the Act were omitted from the tabulation.

ALL OF THE LOCAL GENERATION OWNED AND OPERATED BY THE CITY OF HOMESTEAD IS DIESEL. IT IS MY UNDERSTANDING THAT A SYSTEM WITH GENERATION OF THIS TYPE IS EXCLUDED FROM JURISDICTION OF THE FUEL USE ACT OF 1978.

The adoption by the Department of Energy of Implementation Rules which expressly recognized the statutory exclusion of internal combustion (diesel) engine prime movers from the provisions of the Fuel Use Act of 1978 was a major improvement over the Implementation Rules as originally proposed.

For one thing, the exclusion of systems using diesel engine prime movers for generation effectively excludes many of the very small systems from the more onerous provisions of the Act.

IT IS STRONGLY RECOMMENDED THAT THE CONTINUED EXCLUSION OF DIESEL EINGINE PRIME MOVERS BE A FACTOR IN ANY RECOMMENDATIONS MADE TO CONGRESS AS A RESULT OF THE ONGOING STUDIES MANDATED UNDER THE FUEL USE ACT OF 1978.

The City of Homestead and other diesel systems are constructively developing ability to utilize waste heat recovery as a part of their generation program. The development of such capability should not adversely affect the position of such utilities whereby they are excluded from the Act. In fact, if it were possible, steps should be taken to encourage the construction of such waste heat recovery capability, but this should be done in a manner which would not, in any way, affect the exclusion of such units from the overall provisions of the Act.

Attachment No. 1 to this letter is entitled: "COMMENTS, PROPOSED RULES FOR IMPLEMENTATION, POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978 (FUA 1978,) Published by Department of Energy Economic Regulatory Administration, Friday, November 17, 1978, Part IV."

Your particular attention is invited to the following paragraphs of Attachment No. 1:

Page No.	Paragraph No.
2	B.
2	C. (and associated sub-paragraphs)

References, Attachment No. 1: (Cont'd)

Page No.	Paragraph No.
4	D.
4	E. (and associated subparagraphs)
5	F. (and associated subparagraphs)
6.	I. (and associated subparagraphs)

*(As noted on Page 7 at the time these comments were written, I considered 100 megawatts or less to be a division point. Further study of the problem has led me to the conclusion, that as noted earlier in this letter, 200 megawatts is a more realistic division point.)

Page No.	Paragraph No.	
7	J.	
8	K.	#-**

#(At the time I prepared these Comments, I was recommending a moratorium until 1990. It is recommended that if legislation can be adopted to exclude systems of 200 megawatts or less, that the reasons stated in Paragraph L would apply to support such exclusion.)

Page No.	Paragraph No.	
8	L.	
9	M.1 (and associated subparagraphs)	
18	M.3 (and associated subparagraphs	
20	M.4 (and associated subparagraphs)	
21	M.5 (and associated subparagraphs)	**
25	2.1	**

**(Subject to the caveat as previously expressed that further study after preparation of these comments indicates that 200 would be a more reasonable breakpoint than 100 megawatts.)

References, Attachment No. 1: (Cont'd)

Page No.	Paragraph No.	
26	2.2	
26	2.4	
26	3. (and associated subparagraphs)	
30	4.1	**

**(Subject to the caveat as previously stated that further study indicates that 200 megawatts is a better dividing point than 100 megawatts.)

30	6.1	***

***(Subject to the recognition that maintenance of the exclusion of systems using diesel engine prime movers is an essential consideration, and if this position is maintained, the fuels decision report would not apply to diesel engine powered systems.)

32	7. (and associated subparagraphs)	**
33	8. (and associated subparagraphs)	**
36	9. (and associated subparagraphs)	**
37	11. (and associated subparagraphs)	**

**(Subject to the further caveat that 200 megawatts should be substituted for 100 megawatts, for reasons hereinbefore stated.)

38	12.	**

**(Subject to the further caveat the 200 megawatts should be substituted for 100 megawatts.)

40	G.2	##

##(This comment would be particularly applicable to generating systems of 200 megawatts or less.)

Attachment No. 2 to this letter is a letter dated March 9, 1979, prepared by Smith & Gillespie Engineers, Inc., on the subject: Powerplant and Industrial Fuel Use Act of 1978, Docket No. ERA-R-78-19.

In this letter, the author used a dividing point of 150 megawatts between small power plants, as defined in the Act, and the very small power plants which I have discussed in the foregoing portions of my letter. For reasons explained in the foregoing, I believe that the dividing point between small and very small should be increased to 200 megawatts. I have reviewed this with the author of the letter, and he concurs with this comment.

I have also reviewed with the author of the letter the proviso that one of the most important steps which the Department of Energy could take would be to maintain, and if necessary, strengthen the exclusion of power systems using diesel engine prime movers from the provisions of the Act; he concurs with this.

The references which are made in the following paragraphs are subject to these comments which will not be repeated in the references which follow. The following page and paragraph references are to Smith & Gillespie Engineers, Inc's letter cited above dated March 9, 1979:

Page No.	Paragraph No.
1	1. (and related subparagraphs)
2	2.1 (and related subparagraphs)
4	2.2 (and related subparagraphs)
5	2.3 (and related subparagraphs)
5	2.4 (and related subparagraphs)
6	2.7 (and related subparagraphs)

Page No.	Paragraph No.
8	2.8.1
8	2.10.1
8	4.
9	5.

The following paragraphs addresses themselves to the particular points raised in the request for information set forth on the excerpt from the FEDERAL REGISTER Volume 45, No. 73, Thursday, April 17, 1980, which was an enclosure to your letter to me dated May 21, 1980. The paragraph references are to the paragraphs stated under "Request for Information".

Reference Paragraph (1):

The operating and development plans and strategies of the City of Homestead to permit compliance with FUA include the purchase of a certain amount of base load, average system cost power from major utilities who have a certain amount of non-petroleum/ natural gas generation on line at present, and who have the capability, because of their size, of constructing additional non-petroleum.natural gas generation. In addition, the City is seeking opportunities to purchase from or joint participation in transmission construction to enable it to utilize hydroelectric power. As a further implementation of its strategy, the City has participated in the experimental installation of a waste heat recovery unit, and should the installation prove practical and economical, would consider further application of waste heat recovery. The City's goals are to operate as efficiently as possible, utilizing outside purchases or joint acquisitions at maximum load factor as needed.

Reference Paragraph (2):

The City of Homestead does not have, nor does it contemplate, the installation of steam power plants utilizing boilers, to which this question would apply. However, in view of the fact that I maintain an active leadership in the Statewide Utility Association, I am awaure of certain problems which I believe must be addressed, in addition to the simple technical and financial feasibility as applied to "boilers". Consideration of the use of coal in many small power plants poses major problems insofar as their location is concerned with respect to environmental considerations; with respect to storage problems; with respect to transportation problems. All of these factors must be given careful consideration.

Reference Paragraph (3):

Please refer to comments under the referenced Paragraph (1). In addition, the City of Homestead has considered participation in generation utilizing solid waste as a fuel. This R & D program was not available to the City of Homestead. The agency developing this study elected to combine their operation with that of Florida, Power & Light Company. Further, the City has considered wind and solar sources, without success, to date. The City, however, has not closed the door and will continue to seek out alternative methods. The principal problem insofar as the City is concerned is that the application of technologies, such as wind, solar, fuel cells, etc., generally involve substantial first cost investments on a relatively unproven technology. The City can and does make investments, such as those it has made in the waste heat recovery, but must, of necessity, limit its participation in such programs so that a failure would not result in catastrophic financial problems to the City and the System. In short, the City would welcome the opportunity of considering programs where the particpation of the City in first cost investment could be limited by application of grants or other support. The City believes it could make a significant contribution, in view of its size and experience, in test programs and would welcome the opportunity of doing so.

Reference Paragraph (4):

Because of the unique nature of the Service Area of the City of Homestead, there are not current local opportunties for cogeneration at this time.

Reference Paragraph (5):

Because of the City of Homestead is a diesel system and therefore is exempt under the Fuel Use Act of 1978, we have no specific problems to report involving exemptions.

Reference Paragraph (6):

The major problems which the City has experienced to date in gaining access to large power plant projects and needed transmission facilities include, but are not necessarily limited to, the following general summary:

> The City is seeking, but has not yet been successful in obtaining access to the purchase of base load power from or participation in Florida, Power & Light Company's nuclear fuel power plants, Turkey Point Units 3 and 4 and St. Lucie 1.
>
> The City has not yet reached agreement with Florida Power and Light Company as to terms and amounts of participation in that Company's nuclear fuel power plant, St. Lucie 2.
>
> In these first two instances, the City of Homestead is a named party in the District Court/ Circuit Court of Appeals case entitled "Fort Pierce Utilities Authority vs. FP & L," CA Docket No. 79-5101 (NRC Docket No. 50-389A).
>
> Through the Florida Municipal Utilities Association, the City of Homestead is seeking relief in matters relating to Florida Power and Light Company's nuclear fuel power plant St. Lucie 2. This is NRC Docket No. 50-389A.
>
> Implementation of positive developments establishing Homestead's interest in the above would probably take place through the Florida Municipal Power Agency.
>
> The City of Homestead has sought and seeks access to a Statewide transmission rate, or at least the right to participate in the ownership of Statewide transmission facilities.

The aspects of the transmission matters are in litigation by the City of Homestead and others, Federal Energy Regulatory Commission (FERC) Docket Nos. 77-175 and 78-19 (CA Docket No. 80-2529).

The City of Homestead has initiated steps to review its possible rights to access SEPA power and to access available economy energy in Georgia and the Carolinas, recognizing that, at least in the long run, the ability to access such hydroelectric and economy energy will depend upon construction of transmission facilities. In all probability, at least as far as remote bulk power transmission faciliities are concerned , the City of Homestead will probably work through the Florida Municipal Power Agency.

Reference Paragraph (7):

The suggestions responding to Subparagraphs (i) (ii) and (iii) have been set forth in the foregoing paragraphs of this letter.

Reference Paragraph (7) (iv) and (v):

These two subcategories have been combined to minimize the repetition that would otherwise occur. There must be maximum coordination between Federal and State programs, policies, and actions. There are "have" and "have not" areas in this country as far as energy is concerned, especially in view of the present emphasis on fuels other than liquid petroleum and natural gas. The State of Florida is blessed with many advantages, but these advantages do not include access to coal nor to hydroelectric energy sources. Regions that do have access to such sources understandably regard them with a relatively high degree of proprietary interest.

The State of Florida will find it extremely difficult to import sufficient coal to make a sizeable reduction in its requirement for petroleum and natural gas. Pending the development of such importation capability, the State must, of necessity, rely on nuclear power, imported electric energy via high voltage transmission, and continued use of liquid petroleum and natural gas.

Federal and State policies, and not necessarily limited to the State of Florida, must work synergistically to address themselves to these problems. It appears to me that these problems are of interest in states other than Florida; however, for the obvious reason that I am familiar with Florida's problems, I am confining myself to this area. To the extent that the comments would apply elsewhere, they should be applied:

> The order in which these subparagraphs appear does not convey an order of priority. Where priority is to be applied, and it should be applied, priority should be given to solving those problems which can be solved first, while at the same time, concurrently working on problems which, because of their nature, involve a later solution.
>
> Nuclear energy must be given careful consideration and the present and potential problems must be constructively addressed. It appears to me that we are losing what should be a viable alternative source of energy by default. We continue to introduce unrealistic indecision and delay into our regulatory processes, not the least of which is what amounts to an effective total shutdown of our fuel reprocessing programs. Problems associated with radioactive waste must be constructively addressed. If I understand what I hear and read, unless we correct our total approach to nuclear energy, we are going to find our own industrial and technological capability shut down, and our former leadership in this field transferred to other nations abroad. Certainly, this cannot be allowed to happen.
>
> Coordinated transmission programs must be undertaken to provide links from areas where non-petroleum fueled energy is readily available to areas where there is a deficiency of such energy. Granted, that there are problems involved in massive transmission construction and in the operation of such facilities, but it appears that

if we are to solve our energy problems, it is going to have to be done through cooperative ventures between all phases of the Electric Utility Industry and that this cooperation must extend across state lines. I do not recommend that this be funded or be made a part of a Federal program; however, State and Federal regulatory agencies must cooperate and must develop a constructive attitude toward fostering such programs.

I believe that the enlightened self-interest of Municipal Electric Systems, joing Municipal agencies, Rural Electric Cooperatives, Rural Electric Cooperatives agencies, individual Investor-Owned Electric Utilities, and associations of such Investor-Owned Electric Utilities must be permitted and encouraged to cooperate effectively in construction of major energy production and transmission facilities. Whatever oversight is necessary to protect the interest of the public, such oversight should be provided. Certainly, there should not be any relaxation of the anti-trust considerations involved. Cooperation there must be, and the Department of Energy should take the position that cooperation there shall be.

I thank you for the opportunity of making these comments. If you have any questions, please let me know.

Respectfully submitted,

CITY OF HOMESTEAD, FLORIDA

Henry C. Peters Jr.

Henry C. Peters, Jr.
Director of Utilities

Enclosures

Public Lighting Department
7500 Jos. Campau Avenue, Detroit, Michigan 48211
(313) 875-0972

Coleman A. Young, Mayor
City of Detroit

June 5, 1980

Mr. Alan W. Starr, Chief
Source Technology and Economics Branch
Division, Power Supply and Reliability
Economic Regulatory Administration
U.S. Department of Energy
2000 M Street, North-West
Washington, D. C. 20461

Subject: Your Letter to Us Dated
May 21, 1980 on How FUA
Affects Smaller Utilities.

Dear Mr. Starr:

We offer the following three general comments:

1. As you stated in your letter, keeping abreast of all of the statutes and regulations affecting the utility business is overwhelming to us. We are trying to have some knowledge of FUA, ECA, PURPA, NGPA, and CAA, all being worked on by DOE, FERC, ERA, and EPA. We should really have several persons assigned to this kind of study work, including both engineers and attorneys.

2. We are seriously affected by the FUA because our 200-MW power plant presently uses oil, but we are trying to be dual-fueled, including natural gas, at least for a few years as allowed by the FUA.

3. We feel that the FUA, as administered by the DOE, is diametrically opposed to the CAA as administered by the EPA. Does the United States want to reduce the use of petroleum or does it want to have clean air or is it willing to compromise?

Recommendations to alleviate the problems of small utilities in complying with the Fuel Use Act of 1978 are:

A. Utilities whose annual kilowatt-hour sales are less than 750,000,000 should be exempted from coverage by the Act. This limit would be consistent with threshold criterion of NECPA.

B. Utilities which have made site changes to accommodate the conversion from coal to oil to meet EPA restrictions, such as building oil storage facilities where coal was formerly stored and which as a result no longer have space either for coal storage or for holding ponds or desulfurization equipment, should be exempted from the Act.

C. Utilities which have generating units (boilers) specifically designed for oil should be exempted.

If you have any questions, please write, or, call me at 1 (313) 875-0972, Extension 301.

Very truly yours,

PUBLIC LIGHTING DEPARTMENT

James A. Williams
James A. Williams
Superintendent

/voh

cc: Mr. John F. Remski, PLD-Engineering

by: Registered Mail -
Return Receipt Requested.

BOARD OF PUBLIC UTILITIES
City of McPherson, Kansas - 67460

Box 1008 Phone 316–241-0661

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June
6
1980

Small Utilities Study
Office of Utility System
Department of Energy
Room 4002
2000 M Street N.W.
Washington, D.C. 20461

Re: PIFUA/1978 Section 744
Small Utilities Impact

Dear Sir:

The BPU, City of McPherson is the second largest municipal generating system in Kansas. The BPU has a generating capacity of 216 MW, and it is totally dedicated to peak load dispatching. All base load energy is obtained through a firm power contract with the Kansas Power and Light Company, and this energy is produced from coal fired steam plants.

1. I would offer the suggestion that small utilities are those with less than 200 Mw of generation and net Kwh sales of 750,000,000. The delineation of 2000 Mw is not realistic.

2. The FUA has provision for exemptions for Peaking Plants. The BPU has obtained an exemption to use NG on that premise. Our petition was drafted on that basis and a temporary exemption was awarded after nearly one year of deliberation. In view of the fact that the Director of DOE was urging us to use natural gas in lieu of other petroleum products, the time to expedite seems unrealistic.

3. The smaller utilities may be the first to develop alternate generating procedures but those procedures are not here today. Most of our small municipals use natural gas in diesel engines, and that load is essentially off peak for the heating season. These diesels provide fine emergency power when Cities are interconnected with power grids.

I would guess that these small generating units could be adapted to burn a synthetic fuel when it becomes available, however the municipal generating system must be kept active during the interim of fuel development.

4. Small systems do not have large professional or administrative staff. The procedures of the federal government to publish information through the Federal Register is a trying thing for nearly all public entities.

The Federal Register is a difficult instrument for small communities to monitor.

Our City receives one copy on a regular basis and it is filed in the county law library.

I find that I must have an attorney translate and consolidate the many words in our working language.

In summary I would say that operations directed from Washington tend to be clumsy and inappropriate. Each agency has their own tunnel vision of their goal or responsibilities and very few provide the necessary service for the customer.

BOARD OF PUBLIC UTILITIES

Don E. Gerard, General Manager

DEG/cc

cc: Kansas Municipal Utilities, McPherson

City of GLENDALE CALIFORNIA

PUBLIC SERVICE DEPARTMENT
WATER – LIGHT – POWER

119 NORTH GLENDALE AVE.
GLENDALE 91206
TELEPHONE (213) 956-2107

June 3, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street NW
Washington, DC 20461

Gentlemen:

In response to your request for information, we will list below a number of problems that the City of Glendale will experience in trying to comply with the Fuel Use Act.

1. Our existing boilers are designed primarily for natural gas fuel with oil as an alternate fuel, and cannot be converted to burn coal.
2. Our experience in trying to obtain alternate fuel sources or energy sources has not been successful. We have attempted to secure participation in numerous outside power plants, but have been unsuccessful in this area.
3. Lack of transmission facilities often makes it not feasible to participate in otherwise acceptable outside plants.

We recommend that amendments be made to the Fuel Use Act to allow continued use of natural gas for utilities' operations when available; this will reduce the need to import foreign oil. Amendments to simplify the exemption process under the Fuel Use Act should also be considered.

Very truly yours

W. H. Fell by L. L. Young

WILLIAM H. FELL
General Manager and Chief Engineer

WRH/nl

The City of Lebanon, Ohio

CITY BUILDING, BROADWAY AT MAIN STREET, LEBANON, OHIO 45036
TELEPHONE 932-3060

June 10, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M. Street, Northwest
Washington, D. C. 20461

SUBJECT: Impact Of Fuel Use Act of 1980 on Small Utilities

Dear Sir:

The cost to convert small units to alternate fuels is so great that this requirement will force these power plants to discontinue operation. A case in point, would, most certainly, be our power plant, which is of 20 megawatts in size and is basically used to augment our two purchase power contracts. This plant permits us to purchase off-peak coal-fired power for less than 30 mils, compared to generating our own at over 30 mils.

As a result, economics alone has forced us to use this base load plant for peaking operations only, and at some point in time, to discontinue the total operation of this plant.

If government is to be involved, the action and emphassis should be to stop future use of oil and force all utilities to interchange power at economical rates. This will encourage the small utilities to purchase energy from coal-fired plants, which would be operating at maximum efficiency. Further action should be taken to encourage the small utilities to purchase a part of the large power plant, rather than add generation. We all know the economical scale and should adhere to it.

The small utilities are soon to become a thing of the past, but, we should take care of these units as long as we can, because they are the cheapest source of generation when complimented with very large coal-fired or neuclear power plants. Obviously, these plants can not continue to operate for twenty to thirty more years. The bulk of these plants will be retired in ten to fifteen years at the most and although slow, the problem will be self-solving. At present, 30 states have Joint Use Acts, and possibly, if the D.O.E. would put some emphasis on the importance of joint use, the other 20 states would come around and join in and encourage the interaction between utilites.

Sincerely yours,

V E Garrison

Victor E. Garrison
Chief Engineer

VEG/cjh

DEPARTMENT OF UTILITIES
ENGINEERING DIVISION
Telephone: 233-6611 Ext. 478
1830 Walker Road
P. O. Box 4017-C
Lafayette, Louisiana 70502

June 6, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and
Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Re: Your Letter of May 21, 1980

Dear Mr. Starr:

The City of Lafayette has been utilizing natural gas as its primary fuel for steam electric generation since 1951. Prior to that time, natural gas and diesel fuel were used with diesel units. There has been and still is an abundant supply of natural gas in this area which could easily provide fuel for domestic and industrial use and for electric generation. A large portion of the gas produced is transported to areas in the East and North. The City of Lafayette has entered into a joint venture with Central Louisiana Electric Company (CLECO) to construct a coal-fired electric generating unit. The City of Lafayette will own one-half (½) the capacity of this unit or 265 MW at a cost of approximately $140,000,000.00. This unit is scheduled to be placed on line in the Spring of 1982. The City of Lafayette's total existing natural gas-fired generating units have a total capacity of approximately 375 MW. The total cost for these units is approximately $49,000,000.00 or $130.00 a kilowatt while the cost of the coal-fired unit is approximately $530.00 a kilowatt. The transportation cost for coal in 1982 will probably be in excess of twice the cost of the coal at the mine.

Many of our citizens ask the question, "Why should we buy coal in Wyoming and have to pay expensive transportation costs when we have an abundance of gas in this area that could be used in the area instead of shipping great distances to the East and North?" It is our opinion that the Department of Energy should concentrate more on reducing the transportation of fuel large distances and attempt to have these fuels burned in the area in which they are produced.

If you have any questions, please advise.

Sincerely,

T. J. Labbe'

T. J. Labbe'
Associate Director of Utilities

TJL:dl

cc: S. J. Richard

LAW OFFICES
MILLER, BALIS & O'NEIL, P.C.
776 EXECUTIVE BUILDING
1030 FIFTEENTH STREET, N. W.
WASHINGTON, D. C. 20005

WILLIAM T. MILLER
STANLEY W. BALIS
ROBERT A. O'NEIL

(202) 789-1450

June 6, 1980

Mr. Alan W. Starr
Chief, Source, Technology and
Economics Branch
Division of Power Supply and
Reliability
Economic Regulatory Administration
Department of Energy
Washington, D.C 20461

Re: Congressional amendments of the Fuel Use Act.

Dear Mr. Starr:

In response to your letter of May 22, 1980, to Mr. Lingenfelder of the Yazoo City Public Service Commission, Yazoo City, Mississippi, I would like to provide you the benefit of Yazoo City's thoughts on this subject.

In the first place, Yazoo City wants to be sure that you do not interpret the lack of response by small utilities as evidence that no serious problems exist and that no legislation and regulatory changes are warranted. To the contrary, the Fuel Use Act, accompanied by its lengthy and complex regulations, has put a tremendous burden on small utilities like Yazoo City.

In the first place, Yazoo City simply does not have the resources or the manpower to cope with FUA. It has been forced to retain outside consultants, both engineering and legal, in an effort to help it (1) understand the FUA and its requirements and (2) meet those requirements.

When you balance the tremendous financial burden that FUA places on small utilities like Yazoo City against the very small gains that can hoped to be achieved by weaning small utilities off of gas, Yazoo City respectfully submits that the public interest would be well served by exempting small utilities like Yazoo City from the FUA. It is our candid belief that Congress could not have envisioned when it enacted the FUA the multitude of problems that this legislation would cause small utilities. Not the least of the end results that such legislation may force, though certainly not intended, is the anticompetitive one forcing Yazoo City to simply foresake municipal ownership. Certainly Yazoo City would resist this result, but you should be aware that onerous legislation such as the FUA could well have that most undesirable effect.

In brief, even if every small utility (defined as a utility with total generating capacity of 100 Mw or less) did not use another Mcf of natural gas or gallon of oil, the amount of such energy sources saved would be miniscule; on the other hand, the cost to small utilities of implementing FUA is staggering. When these matters are weighed, we submit that the public interest requires exemption of small utilities from the purview of FUA, which can most easily be accomplished by amendment to FUA as recommended above.

If we can be of any further assistance in this matter, please contact either the undersigned or Mr. Lingenfelder of Yazoo City as this matter is of the utmost concern and importance to Yazoo City.

Very truly yours,

William T. Miller

William T. Miller

WTM/stp

CITY of DENTON, TEXAS MUNICIPAL BUILDING / DENTON, TEXAS 76201 / TELEPHONE (817) 566-8200

June 24, 1980

Mr. Allan W. Starr
Division of Power Supply and Reliability
US Department of Energy
2000 M Street, N.W.
Washington, D.C. 20461

Dear Sir:

The following comments are in response to the April 17, 1980, Federal Register notice regarding comments relative to Section 744 of the Powerplant and Industrial Fuel Use Act of 1978 (FUA). Section 744 requires the Department of Energy (DOE) to conduct a study of the problems of compliance with FUA experienced by electric utilities with a total system generating capacity of less than 2,000 MW. Our review of FUA as it impacts the City of Denton concludes the following points:

> The FUA should be repealed. This position is taken because we feel the City of Denton, through its membership in the Texas Municipal Power Agency (TMPA), is already accomplishing the intent of the law by virtue of its commitment to new nuclear and lignite generation. This generation will displace existing natural gas/oil fired generation. This commitment is based on normal financial and engineering analysis and does not require the artificial fuel prohibitions contained in the FUA.
>
> The regulatory burden of FUA is considerable and has created significant difficulties in the development of an acceptable compliance strategy. This problem is compounded by FUA regulations that are published in a random fashion in "interim" form. We found it necessary to hire Stone and Webster Management Consultants, Inc., to collect the current regulations and develop a strategy for us prior to a regulatory deadline for one particular compliance option.

Our compliance strategy has been based on "interim" FUA reguations. If the "interim" regulations are changed, these revisions could easily affect our selected strategy at this time. Given the deadline of the system compliance option (SCO) strategy, we find this problem of particular concern.

The FUA discretionary fuel prohibitions add to the uncertainty in developing an acceptable compliance strategy. The discretionary fuel prohibitions may negate our long-term planning effort because future decisions by DOE in this area can affect our system fuel mix. Such changes could cause powerplant conversions or early retirements of TMPA member city units. Both results may increase the cost of electricity to our customers in the future.

The current SCO exemption regulations cannot cope with a power pool operation. As a member in TMPA, we know that pooled resources create economies for our customers. The current SCO regulations do not allow the pooling of gas allowances within an organized power pool for the benefit of the pool members.

The member cities of TMPA have 24 existing steam and gas turbine generating units. We anticipate the need for some of these units through 1999. The units required in this period can be gas or oil fired. If the regulations on gas are imposed as we understand them, we see no acceptable alternative but to burn expensive oil in these units.

Respectfully,

R. E. Nelson

R. E. Nelson
Director of Utilities
City of Denton Texas

REN/gcr
cc: file

TOM MOODY
MAYOR
ROBERT C. PARKINSON, P.E.
DIRECTOR OF PUBLIC SERVICE

CITY OF COLUMBUS
OHIO

HENRY A. BELL, P.E.
SUPERINTENDENT

DIVISION OF ELECTRICITY
90 W. BROAD STREET
COLUMBUS, OHIO 43215

June 23, 1980

Department of Energy
Washington, D.C. 20461

Attention: Mr. Alan W. Starr

RE: Department of Energy, Fuel Use Act

Dear Mr. Starr:

This is in response to your letter of May 22, 1980. The City of Columbus, Division of Electricity, is proceeding with construction of a Refuse Fired 90 Megawatt Power Generating Station. Since we do not use natural gas or fuel oil, we are effected very little with the Fuel Use Act.

Should you have a concern other than this point, please let us know.

Very truly yours,

Henry A. Bell

Henry A. Bell, P.E.
Superintendent

HAB:iy

CITY OF COLUMBIA, MISSOURI P.O. BOX N COLUMBIA, MO. 65201

June 17, 1980

Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Divison of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Re: Problems with the Fuel Use Act

Dear Mr. Starr:

Your letter regarding comments on the problems in complying with the Fuel Use Act was evidently delayed in arriving here. Although the deadline for comments has passed, I thought I would write you anyway in the hope that my comments might still be helpful.

The situation here in Columbia is probably not unique. Our newest and most modern unit is a 1969 vintage gas/oil-fired steam unit. We also have a 10 MW gas/oil-fired combustion gas turbine although this unit is strictly a peaking plant. The reason that a gas/oil unit was chosen was that the Federal policies back in the late 60's encouraged that type of installation if for no other reason than pollution control. The unit was added to an existing steam plant in an urban area and the costs of pollution control equipment combined with the cost differential for fuel made a gas/oil unit the only way to go. The unit is a true central station type steam unit so it cannot be cycled like a peaking unit. The unit was never designed for coal, therefore the volume of the combustion chamber is too small to allow the unit to achieve full load with coal as a fuel, even if it is pulverized. There are no grates in the unit and no provisions for ash handling. Thus, the unit practically needs a new boiler to handle coal as a fuel. Since the unit was designed for gas/oil, a separate short stack was built and no pollution control equipment is in place. Thus, we would also need a new stack, and precipitators, and scrubbers.

The fuel costs for this unit on gas are in the range of 3.5¢/kWh. If run on fuel oil, the cost is in the range of 8.5¢/kWh. The fuel costs are such, compared to our coal units, that we run it mainly in the peak load summer months. We can't afford to run it at all on oil without putting an extreme penalty on our customers. Because we have over half of our system load in capacity of our own, we are able to purchase the balance of our requirements at a very reasonable price from another utility. If our 35 mW unit cannot be operated, the whole balance will be changed and our supplier will charge us under an entirely different scheme that will almost double our demand costs and make it exceedingly difficult for us to be competitive. We currently have a five-year exemption under the Fuel Use Act and, quite frankly, we didn't know what we were going to do it you didn't give it to us.

A BICENTENNIAL COMMUNITY

What are our alternatives? As I see it, they are as follows:

1. Shut down the unit and abandon it. This will mean shutting down a modern unit. It will reduce system capacity in this area. It will alter existing relationships with our existing supplier and put a large economic burden on our customers. And it will mean that we will have to continue to make payments on revenue bonds for a unit we can no longer use. If exemptions were granted to burn gas until 1989, the impact might not be quite as serious, but it would still have an adverse impact.

2. Convert to coal. As you can see from a description of our situation, a coal conversion is almost out of the question. The coal conversion costs (including a new boiler, stack, coal handling, ash handling, and pollution control devices) in today's dollars will probably far exceed the original installation cost of the unit. It will greatly increase the cost of our power and not increase our capacity. The only funds that are available to a small municipal utility are revenue bonds that must be voted on and approved by the citizens in a referendum. Not only will it be difficult to explain to the public why we have to do the project, but the magnitude of the expenditure will have a very detrimental effect on our bond coverage for any other projects. The only way that we can see that it will be possible to do a conversion would be if the Federal government would find it to be in the public interest to make grants to small utilities to assist in the conversions.

3. Burn fuel oil. This option will place a very heavy economic burden on our citizens and will only serve to increase the imports of fuel oil that we are already attempting to reduce. Due to our exemption, it has been well over a year since we burned any fuel oil at all and we were hoping that we were making a positive contribution to reducing our reliance on the Middle East.

4. Burn gas as a fuel. This seems to us to be the only really logical solution. It is difficult to believe that small units such as ours are going to jeopardize the whole natural gas fuel supply situation in our country. The ever-increasing costs of natural gas are going to naturally reduce the consumption of gas as a fuel due to economic choices. We, for example, are already using our unit on a seasonal basis rather than year around. Another opportunity we hope to take advantage of is in joint pooling. Our State has passed enabling legislation that will allow us to form a municipal agency that can sell bonds and build large coal-fired units for a group of municipals to share in. As these units come on the line, our gas/oil-fired unit can go into the system reserve which means it will be very valuable but will be run very little. We will still need a reliable fuel supply, however. We think it makes sense to continue to allow these units to be run on natural gas, both for economical reasons, and in order to hold down oil imports. And until such time as we can get a unit built, and that can take ten years due to Federal environmental requirements, we need the unit to meet our summer loads.

This letter has been very lengthy but I hope that by describing our situation here in Columbia that you can get a feel for some of the problems that those of us who are out here in the world trying to keep the lights on are faced with. What this all boils down to is that I believe that the proper policy for the Federal Government to adopt would be:

1. Allow small municipal units such as ours to continue to burn natural gas (including peaking plants), and

2. For the Federal Government to encourage in every way possible the formation of joint municipal agencies with access to the transmission grids so as to allow the small municipal units to be used as peakers and system reserve, and to be phased out in an orderly and economic manner.

I believe this policy would help municipals to deal with the problems without going bankrupt, would make a significant step in holding down oil imports, and would not endanger the supply of natural gas. In a similar manner, I would also encourage the passing of a synfuels bill, and a strong government grant program to encourage the development of hydro generation at existing dams.

Very truly yours,

Richard E. Malon, P. E.
Director, Water and Light Department
Chairman, Missouri Joint Municipal Electric Utility Commission

CC: Senator Eagleton
Senator Danforth
Alex Radin, APPA
Executive Committee, MJMEUC
Columbia City Manager

REM/ld

Tucson Electric Power Company

220 West Sixth Street
P. O. Box 711
Tucson, Arizona 85702

Einar Greve
Executive Vice President

(602) 622-6661

May 10, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy, Room 4002
2000 M Street, N. W.
Washington, D. C. 20461

Gentlemen:

This letter is in response to the notice published in the Federal Register on April 17, 1980 (45 FR 78) wherein the Economic Regulatory Administration requested comments on the problems of compliance with the Powerplant and Industrial Fuel Use Act of 1978 ("FUA") experienced by electric utilities with a total system generating capacity of less than 2,000 MW. As Tucson Electric Power Company ("TEP") falls within this classification, we therefore submit the following comments for your consideration.

TEP is presently participating in and developing remote coal-fired powerplants which are base loaded units. The geographic location of these plants averages approximately 400 miles from our local load area. Our local generation consists of much smaller capacity oil- and/or gas-fired steam units, utilized for area protection and load regulation, and small combustion turbines, utilized for peaking service.

The problems we foresee in converting our existing local steam units to coal include the following:

(1) Excessive costs.

(2) The conversion of the existing boilers for coal use may result in up to a 50 percent loss of capacity.

(3) In lieu of converting the present boilers, which would result in a loss of capacity, new boilers could be built for the full replacement of the capacity of the present boilers. However, the geographic location of our Irvington power plant lies underneath one of the glide paths of Tucson International Airport. The height requirements for new boilers would be in excess of the height restrictions imposed on the plant due to its proximity to the airport facilities.

(4) The loss of the generating capacity of each unit during the conversion period, which is estimated to be approximately a year per unit.

(5) Environmental problems, as these units are located in populated areas in and around the City of Tucson.

We have investigated the possibility of using unusual alternate fuels in these units, such as coal gasification, but have ruled them out due to excessive costs and environmental considerations.

ERA has recently granted temporary public interest exemptions for our local generation units. These exemptions were granted for a period of five years for the combustion turbine units and eighteen months for the steam units. In January of 1980, when our applications for our steam units were still pending, the ERA published a notice in the Federal Register wherein they proposed to deny temporary public interest exemptions to units which burn high sulfur oil (in excess of 0.5%). As we are one of the utilities which does use high sulfur oil, we were particularly concerned. Ultimately, the ERA did not adopt this policy, and we were granted exemptions for the steam units, but the possibility of denial left us in limbo for several weeks. Even after the exemptions were granted, they are only applicable for eighteen months and it is now unknown whether any extensions will be granted. If extensions are not granted, we will be forced to burn higher cost oil and will not be able to utilize natural gas supplies which we foresee will still be available over El Paso Natural Gas Company's system.

For all the above reasons, we would suggest that Congress and the ERA consider the following suggestions:

(1) Grant permanent exemptions from the prohibitions of the FUA for electric utilities with a total system generating capacity of less than 2,000 MW.

(2) In the alternative, grant permanent exemptions from the prohibitions of the FUA for

  (a) steam units which qualify as intermediate powerplants, and

  (b) combustion turbines which qualify as peaking powerplants.

Thank you for your consideration of these comments.

Sincerely yours,

Einar Greve

EG:jec

ISHAM, LINCOLN & BEALE
COUNSELORS AT LAW

1120 CONNECTICUT AVENUE, N.W.
SUITE 325
WASHINGTON, D.C. 20036

TELEPHONE 202-833-9730

CHICAGO OFFICE
ONE FIRST NATIONAL PLAZA
FORTY-SECOND FLOOR
CHICAGO, ILLINOIS 60603
TELEPHONE 312-558-7500
TELEX: 2-5288

May 20, 1980

BY MESSENGER

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street, N.W.
Washington, D.C. 20036

ATTENTION: Mr. Alan W. Starr

Re: Request for Comments on Report to Congress on the Study of Compliance Problems of Small Electric Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978

Dear Mr. Starr:

Enclosed for your consideration are requests for extension of time within which to file comments in connection with the above matter, submitted on behalf of West Texas Utilities Company, the Committee on Power for the Southwest and Western Farmers Electric Cooperative.

Very truly yours,

David Stahl

David M. Stahl

DMS/lhm
Attachments

cc: Jay M. Galt, Esq.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Report to Congress on the
Study of Compliance Problems
of Small Electric Utility Systems
with the Powerplant and Industrial
Fuel Use Act of 1978

REQUEST FOR EXTENSION OF TIME FOR FILING COMMENTS

The Committee on Power for the Southwest (the "Committee") and Western Farmers Electric Cooperative ("Western Farmers") respectfully request that the time within which comments must be filed in connection with the above Report be extended to June 6, 1980.

Western Farmers is an electric generation and transmission cooperative located in Anadarko, Oklahoma providing wholesale electric power and energy to 19 rural electric distribution cooperatives (which in turn serve more than 130,000 ultimate consumers) and 6 municipally-owned electric systems. The Committee is an Oklahoma non-profit corporation organized to assist its 175 rural electric cooperative members and 65 municipally-owned electric system members, which are located or doing business in the States of Missouri, Oklahoma, Texas, Arkansas, Louisiana and Kansas, in obtaining electric power and energy for the needs of their member-consumers. Both Western and the members of the Committee are electric utility systems with total system generating capacity of less than 2,000 megawatts and would be included in the Report and therefore intend to file comments.

The current deadline for filing comments, May 23, 1980, imposes a substantial hardship on Western Farmers and the Committee. Neither Western Farmers nor the Committee will be able to completely coordinate all the views of their respective members into form for filing by that date. Since both Western Farmers and the Committee believe that a coordinated set of comments will be the most effective way to fully inform the Secretary of their views, they respectfully request that they be given until June 6, 1980 to file their comments.

Respectfully submitted,

LOONEY, NICHOLS, JOHNSON & HAYES

By Jay M. Galt
Jay M. Galt, Esquire
Attorney for

Western Farmers Electric Cooperative
and
Committee on Power for the Southwest

Looney, Nichols Johnson & Hayes
219 Couch Drive
Oklahoma City, Oklahoma 73102

Dated: May 20, 1980

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

ECONOMIC REGULATORY ADMINISTRATION

Report to Congress on the
Study of Compliance Problems
of Small Electric Utility Systems
with the Powerplant and Industrial
Fuel Use Act of 1978

REQUEST OF WEST TEXAS UTILITIES CO. FOR ADDITIONAL TIME WITHIN WHICH TO FILE COMMENTS

West Texas Utilities Company ("WTU") respectfully requests that it be granted an additional 14 days within which to file its comments in response to the Economic Regulatory Administration's ("ERA") Notice of Public Meeting and Request for Comments in connection with the above-designated Report.

On April 17, 1980, by notice in the Federal Register, the ERA requested that any person caring to comment on the proposed Report should file comments on or before May 23, 1980. WTU is an electric utility providing service to wholesale and retail customers in north, central and west Texas. At December 31, 1979 WTU had installed generating capability of 1054 megawatts and a 1979 peak load of 819 megawatts. WTU is, therefore, a small electric utility system within the meaning of Section 744(a) of the Fuel Use Act and would be covered by the proposed Report and consequently intends to file comments addressed thereto.

WTU began preparing its comments shortly after April 17, 1980. However, on May 15, 1980 the ERA held its only public hearing on the proposed Report, in Dallas, Texas. Representatives of WTU attended this hearing. As a result of matters discussed at this hearing WTU desires to reconsider certain of the comments it originally proposed to file. Because of the short time between the public hearing and the date on which comments are due to be filed WTU is unable fully to reevaluate and refine its original comments and make necessary revisions without a brief extension of time. WTU believes that such an extension will permit it to file more complete and precise comments with the Department of Energy and thereby permit the Department to forward to Congress a Report based on a more complete record, and therefore is in the public interest.

WHEREFORE, WTU respectfully requests that it be granted until June 6, 1980 to file its comments in response to the April 17, 1980 Notice of Public Meeting and Request for Comments in connection with the Report designated above.

Respectfully submitted,

ISHAM, LINCOLN & BEALE

BY David Stahl

David M. Stahl
Attorney for
West Texas Utilities Co.

Isham, Lincoln & Beale
1120 Connecticut Ave., N.W.
Suite 325
Washington, D.C. 20036
Tel.: (202) 833-9730

DATE: May 20, 1980

5-14-80
WTU CO.

WEST TEXAS UTILITIES COMPANY

COMMENTS ON "STUDY OF COMPLIANCE PROBLEMS OF SMALL ELECTRIC UTILITY SYSTEMS WITH THE POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978"

1) WTU's service area is located in a sparsely populated area of West Texas stretching from the Red River to the Rio Grande. WTU provides dependable electric service to approximately 150,000 customers in a 53,000 square mile territory covering the heart of Central West Texas. The service area includes 167 communities, farms, ranches, and 18 Rural Electric Co-Ops located in 53 Texas counties.
2) Available water supplies are very limited in WTU's service area, which could possibly support electric generation from alternate fuel sources, such as coal.
3) WTU's system was specifically designed around serving the needs of its customers from a plentiful supply of natural gas which was and still is the most reasonably priced fuel in our service area. Abundance of this fuel in our service area makes it in the public interest as well as the interest of our ratepayers for continued use of natural gas beyond 1990. WTU's gas-fired plants are relatively small and remotely located to provide better reliability of service through area security while making the best possible use of available water resources and providing units better suited to peaking service as needed.

4) It would not be in the best interest of the public or our ratepayers to abandon our gas-fired equipment & install expensive coal fired generating equipment for replacement. We must extend the useful life of this existing equipment by seeking exemptions as pointed out in Item (5) below. None of our gas-fired boilers can be converted to burn coal. A new coal-fired boiler and necessary auxiliaries would be required at each plant site.

5) Temporary or permanent exemptions for continued use of natural gas in our existing boilers will be necessary.

6) Based on current projections and load forecasts, WTU will still require an estimated 54% of its fuel requirements come from natural gas in 1990. This is true even though we plan to convert our system to coal-fired generation as rapidly as is economically feasible by starting up a jointly-owned coal-fired generating unit in 1987, followed by additional coal and lignite-fired units as needed to meet our customer needs.

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
POUGHKEEPSIE, N.Y. 12602

CHARLES E. RIDER
SENIOR VICE PRESIDENT
CORPORATE PLANNING

June 2, 1980

Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Starr:

This replies to your letter of May 22, 1980 to Mr. H. Clifton Wilson, President of Central Hudson.

We agree that the report being developed by your staff on the problems small utilities are facing in complying with the Powerplant and Industrial Fuel Use Act of 1978 is of great importance. Accordingly, on May 20, we mailed to you an eleven-page memorandum describing the problems Central Hudson faces in this regard and outlining steps which should be taken to overcome them.

Since our May 20th mailing to you may have gone astray, I am enclosing another copy for your use. Please note the correction of a typographical omission on Page 9. If the copy mailed earlier reaches your office, I would appreciate your help in assuring that that copy is also corrected.

Very truly yours,

Charles E. Rider

CER/etk

xc: Mr. H. C. Wilson (w/o enc.)
D. W. Grant, Esq. (w/o enc.)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
POUGHKEEPSIE, N.Y. 12602

CHARLES E. RIDER
SENIOR VICE PRESIDENT
CORPORATE PLANNING

May 20, 1980

Small Utility Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street, N.W.
Washington, D.C. 20461

Re: Report to Congress on the Study of Compliance Problems of Small Electric Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978

Dear Sirs:

A. Introduction

In connection with your request for comments published at 45 Federal Register 26117 (April 17, 1980) on the problems small utilities face with the Powerplant and Industrial Fuel Use Act of 1978 ("PIFUA"), we would like to share with you the problems which Central Hudson Gas & Electric Corporation ("Central Hudson") faces regarding the opportunities available to reduce its dependence on oil and gas for electric generation.

Central Hudson is a combination utility company which furnishes retail electric service to approximately 210,000 customers in the mid-Hudson region of New York State. Central Hudson's total installed electric generating capacity is approximately 930 Mw. of which approximately 45 Mw. are hydro and 885 Mw. are fired by petroleum products or natural gas.

There are two ways in which Central Hudson can reduce its dependence on foreign oil: (i) to foster conservation and (ii) to develop alternative sources of energy. As a matter of public policy, Central Hudson is pursuing a vigorous campaign to educate and assist customers in conserving energy including the performance of energy audits for customers and the provision of financing for energy conservation equipment on customer premises.

The development of alternative sources of energy to oil and gas, such as coal conversions and nuclear plants, are beset with substantial problems which can be characterized as falling into two broad categories: (i) regulatory, and (ii) financial. To a great extent the second problem is substantially influenced by, and has resulted from, the first problem. However, both problems must be dealt with if we realistically expect small utilities like Central Hudson to be able to finance alternative sources of generation such as coal conversion.

Since the primary thrust of PIFUA is to encourage utilities to shift from gas and petroleum to coal, these comments will deal mainly with the problems Central Hudson faces when considering coal conversions.

B. Coal Conversion of Danskammer Units 3 and 4

One of Central Hudson's major generating stations is the Danskammer Plant which consists of four units installed during the period 1953-1967. These units were originally constructed to burn coal but were converted to oil during the period 1970-1971 due to the superior economics of oil at the time and in anticipation of the establishment of more stringent environmental requirements. In 1975 the Federal Energy Administration issued a prohibition order for

Danskammer Units 3 and 4 under the Energy Supply and Environmental Coordination Act of 1974. At the time the prohibition order was issued, Central Hudson opposed the conversion of Danskammer Units 3 and 4 to coal because it was not apparent that the economics justified such a conversion. Since that time, however, the drastic increase in the price of oil has altered the relative economics so that it is now apparent that conversion to coal would result in a substantial decrease in the cost of power generated by Danskammer Units 3 and 4. The Company, therefore, would now favor the conversion of these units if a way could be found to finance the conversion. Unfortunately, for reasons which are explained in some detail in the following pages, the Company's current financial condition is such that it would have serious difficulty in obtaining the capital funds necessary to finance the conversion.

If Danskammer Units 3 and 4 were to be converted and could burn coal without the installation of flue gas desulfurization ("FGD") the cost, as currently estimated, would be approximately $80 million. If FGD were required for the burning of coal the estimated cost would increase to about $140 million. The Company is already committed to a five-year construction program which will require it to raise in excess of $184 million over the next five years.(1) This program, by itself, would result in a 46 percent increase in the Company's total capitalization by 1984. Adding to this construction program the coal conversion of Danskammer Units 3 and 4 would entail a 67 percent increase in total capitalization without FGD or an 81 percent increase if FGD should be required. The following account of the difficulties which Central Hudson is encountering in financing only the construction program, to which it is already committed, makes it clear that an attempt to add to that program the cost of coal conversion would seriously compromise the Company's ability to market its securities.

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(1) The principal expenditure under this five-year construction program is Central Hudson's 9% participation in the construction of the Nine Mile Point Nuclear Unit 2 in Upstate New York which upon completion would assist the Company in reducing its use of imported oil.

C. Central Hudson's Recent Financial Problems

In February of this year Central Hudson had planned to issue 850,000 shares of its common stock. Shortly prior to the proposed sale of the stock, Central Hudson was advised by its underwriters that it would not be possible to sell 850,000 shares and the offering was reduced to 500,000 shares. Despite this reduction the shares sold at a market price substantially below book value which was the fourth time in the last six years that Central Hudson had been required to issue shares at less than book value.

To further finance its construction program, Central Hudson issued $25 million of 12 3/8% First Mortgage Bonds on May 23, 1980. Because of Central Hudson's financial condition, the principal bond rating agencies have warned the Company that unless the Company's financial condition can be improved they will be unable to retain the current A/A- rating for its debt securities and will be obliged to downrate them for future issues. Should this occur it will become substantially more difficult for Central Hudson to sell its debt securities.

Central Hudson's depressed financial condition is a result of factors that have led to a weakening of the electric utility industry generally in our country. These factors include: (i) the special vulnerability of utilities to inflation and high interest rates, (ii) local regulatory ratemaking policies which favor short-term advantage to the ratepayers over the long-range public interest, and (iii) increased uncertainty regarding regulatory policies on alternative fuels such as nuclear and coal.

In order to understand how these factors have affected Central Hudson, it is necessary to look briefly at the history of the last fifteen years. In the late 1960's, as inflation began to be a significant problem, Central Hudson, whose financial condition had been excellent in the early and mid-1960's, began to experience deteriorating financial results. This deterioration coincided with the embarking by Central Hudson on a substantial construction project, the Roseton Electric Generating Station in which Central Hudson initially had a 20% interest. By late 1969, it became apparent that Central Hudson would be required to request a general rate increase, a course of action it had not had to take since 1959. However, because of the time period necessary for regulatory consideration of rate increases, it was not until early 1971 that the New York State Public Service Commission granted Central Hudson permission to increase its rates. However, notwithstanding that rate increase and subsequent rate increases approved by the New York Commission in 1974, 1977 and 1979, Central Hudson has not been able to earn even the minimal rates of return authorized by the Commission in any year since 1969, with the single exception of 1972. As a result the market price of Central Hudson's stock has fallen substantially below book value.

During the 1970's, inflation combined with regulatory lag, economic recession and unpredictable customer consumption patterns have prevented Central Hudson from achieving financial results satisfactory to investors. Investors' perception of Central Hudson as an investment opportunity has also been affected by problems which have afflicted other utilities such as the passing by Consolidated Edison Company of New York, Inc. of its common stock dividend in 1974 and the recent Three Mile Island incident. Moreover, the attempts by Central Hudson to obtain adequate rate relief from the New York Commission have been hindered by the policy of the Commission to set rates at the lowest justifiable level. This policy provides for no cushion against unforeseen adverse occurrences and leads to an almost preordained inability to achieve adequate earnings. In fairness to the New York Commission, this policy reflects its concern over not burdening electric utility customers more than absolutely necessary. This policy, however, may be contrary to the public interest if it renders utilities unable to finance capital improvements needed to displace use of foreign oil.

The adverse consequences of the policy of setting rates at the lowest justifiable level is exacerbated by other New York Commission policies, which adversely affect the ability of Central Hudson to finance construction projects, among which are mandatory flow-through to customers of tax benefits intended by the Congress to facilitate investment, refusal to allow construction work in progress in rate base, refusal to allow accrual of allowance for funds used during construction net of tax, and other policies which adversely affect cash flow and hence the quality of utility earnings as perceived by investors.

The regulatory policies described above and the failure of the regulatory response to the problems of inflation evidenced during the past eleven years have resulted in an extreme reluctance by investors to devote their money to utility investments in New York State, because they do not believe that they will earn a fair return on such investments.

Given these facts, Central Hudson will not be in a position where it can finance coal conversions and other projects designed to reduce dependence on foreign oil, such as nuclear plants, unless the following changes are made in regulatory policies:

(1) Rates of return should be established by State regulatory agencies not with an eye to constraining them at the lowest justifiable level, but rather at a level which would provide a cushion against unanticipated adverse occurrences;

(2) Regulatory policies which adversely affect the cash flow of utilities should be reconsidered with a view towards providing internal funds and real cash earnings to support construction programs; and

(3) Regulatory policies regarding depreciation should be revised to reflect the economic reality of premature technological obsolescence and the declining value of the dollar.

Over time, these regulatory changes would improve a utility's ability to finance coal conversions and other projects designed to reduce dependence on oil, but that result would probably not be fully realized until the consequences were reflected in financial results over several years. Accordingly, more immediate assistance to promote coal conversions is necessary.

In view of the fact that a reduction in oil imports would benefit the entire nation, the most equitable approach would be to provide federal grants substantially equal to the cost of conversion. If, however, this proved to be impossible, a viable, but less equitable, approach would be to provide interest free federal loans equal to the cost of conversion. Such loans would be repaid over a reasonable period out of the fuel cost savings realized after conversion subject to the limitation that to the extent fuel cost savings did not aggregate the cost of conversion the remaining portion of the loan would be forgiven. Failing either of these alternatives, state regulatory commissions should be required to allow utilities to (i) add interest on funds borrowed to finance conversions to fuel adjustment charges during the construction period and (ii) utilize a portion of the fuel cost savings resulting from the switch to coal to amortize their investment in conversion over a reasonably short period and to provide a reasonable return on the unamortized portion thereof. After such investment had been amortized, 100% of fuel cost savings would flow to customers.

D. Environmental Constraints

Another substantial impediment to coal conversion is the attitude of the United States Environmental Protection Agency ("EPA") to coal conversion. Central Hudson's experiences with the EPA regarding the proposed conversion of Danskammer Units 3 and 4 leads Central Hudson to believe that the EPA will adopt unrealistically restrictive assumptions and procedures to assure that the most stringent pollution control technology be applied to units which are converted to coal. Unless moderated, the EPA's position will increase the cost of coal conversions and the difficulty of financing them. Central Hudson believes that Danskammer Units 3 and 4 could burn eastern coal with a sulfur content of about 2% and meet all applicable air quality standards without FGD, if a stack conforming to good engineering practice (2½ times facility height) were installed.

Central Hudson has performed air dispersion modeling which supports this position. However, the EPA has challenged Central Hudson's model and proposes a model which Central Hudson believes to be unrealistic to the extent of possibly overstating predicted pollution concentrations by a factor in excess of 2.

Not only would FGD reduce the cost of coal conversion, it would also spare Central Hudson, and the mid-Hudson region, the difficulties of disposing of FGD sludge. Disposing of the sludge will add considerably to the cost of operating the units after conversion. Moreover, given the strength of public opposition to the siting of waste disposal facilities, it is not evident that adequate disposal areas can be found for the sludge which would be created if FGD were required.

The EPA's negative attitude to coal conversion underscores a substantial obstacle to accomplishing such conversions, i.e., lack of coordination among the administrative agencies involved. There is a tendency, which Central Hudson has observed, for each agency to maintain that the responsibility for making conversion possible resides in some other agency, and that its requirements and timetables cannot be altered. Under such a circumstance, no accommodation is possible and everything remains at a standstill.

The problems of inter-agency coordination are heightened where an agency, such as the EPA, takes an extreme and narrow approach to coal conversion and does not consider the issue in a broad perspective with a view to facilitating the program in the national interest. If coal conversions are to be expected, Central Hudson believes that the EPA's position must be moderated or some means must be developed to spread the burden of the EPA's policy to all who will benefit from the reduction in demand for oil, namely, the nation as a whole, rather than allowing it to fall exclusively on customers supplied by those power plants, predominantly in the Northeast, which are convertible from oil to coal.

A factor which contributes to the EPA's position is that certain pollutants, most notably sulfur oxides emitted from power plants in the Midwest and metal smelters in Canada, increase atmospheric SO_2 concentrations and contribute to "acid rain" in the Northeast. The EPA fears that coal conversions in the Northeast would further aggravate these problems. However, rather than seeking to limit emissions from the Midwestern sources which are now allowed to burn high sulfur coal, the EPA has chosen to limit emissions from the converted plants in the Northeast to the very low levels emitted when low sulfur oil was burned. This position unduly burdens efforts to convert to coal in the Northeast. It is Central Hudson's position that a more equitable system is needed which would require all sources contributing to the problem to adhere to reasonably consistent standards. The retrofitting of FGD equipment on a power plant which converts to coal can be as expensive and difficult as the similar retrofit on a power plant which currently burns coal. It does not appear to be equitable for the converting power plants to be required to incur the expense of the retrofit while plants now burning coal are spared such expense and, in addition, are allowed to burn higher sulfur coal than Central Hudson would burn.

Until this issue is confronted and addressed by spreading the costs of burning coal equitably over all regions of the United States, coal conversions in the Northeast will be difficult to accomplish.

* * * * * *

We trust that the above observations are helpful in your study and we urge that serious consideration be given to them.

Very truly yours,

Charles E Rider

CER/etk

WWP 3115 REV 8-73

THE WASHINGTON WATER POWER COMPANY

P.O. BOX 3727 • SPOKANE, WASHINGTON 99220 • (509) 489-0500

H. W. HARDING
VICE PRESIDENT
POWER SUPPLY

May 23, 1980

Mr. Howard F. Perry
Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002, 2000 M Street, N.W.
Washington, D. C. 20461

Dear Mr. Perry:

In response to your request for comments relating to the Economic Regulatory Study of the problems of compliance with the FUA issued April 11, 1980, The Washington Water Power Company (Company) submits the following.

The Company respectfully requests these comments be accepted and considered although we are unable to comply with the May 23 deadline. The Mt. St. Helens erruption created a state of emergency and closed down all business activity, including cessiation of airplane flights and mail service in Spokane from May 18th through 21st.

Very truly yours,

Glenn Nogle

Glenn Nogle, Manager
Resource Planning & Contracts

GN:kn

COMPLIANCE PROBLEMS OF SMALL ELECTRIC UTILITY SYSTEMS WITH THE POWER PLANT AND INDUSTRIAL FUELS USE ACT OF 1978

INTRODUCTION

The Washington Water Power Company is an investor-owned utility founded in 1889 and is currently engaged in the generation, transmission and distribution of electric power to 218,000 customers in eastern Washington, northern Idaho, and western Montana. The Company also distributes natural gas to 74,000 customers in eastern and central Washington and northern Idaho. Prior to 1974, the Company's own energy resources were entirely hydroelectric. Unfortunately, the continued development or participation in large-scale hydro resources by the Company has been virtually eliminated as a result of federal legislation and other environmental considerations. The Company has been turning increasingly towards coal, nuclear and other sources of generation to meet its growing loads. Table I shows the Company's resource mix at the present time, and the predicted resource mix for 1990.

The Company is a member of the Northwest Power Pool and is a party to the Pacific Northwest Coordination Agreement. Through this agreement vast hydroelectric resources of the Northwest utilities are coordinated to achieve optimum generation for the region. Within this region energy resource availability is highly dependent upon weather and streamflow conditions. This problem is particularly acute for The Washington Water Power Company since a high percentage of its resources are presently hydroelectric. During years of good streamflow, there is infrequent demand for the Company's two combustion-turbine facilities except during very cold weather. However, during poor water years, such as has been experienced during three out of the past four years, the "peaking" combustion-turbines have been required to operate over extended periods of time to provide energy to meet the Company's requirements. It is for this reason that some of the provisions of the Fuels Use Act are particularly troublesome. Since poor water conditions normally do not occur with a high frequency, it would be advantageous that the 1500-hour restriction of the Fuels Use Act in any one year be changed to an average of 1500 hours running time over a period of years, for instance, a five or ten-year period.

TABLE I

The Washington Water Power Company
System Resources - Mw

	1980-81		1990-91	
	Jan Peak	Avg. Annual Energy	Jan Peak	Avg. Annual Energy
System Hydro	936	346	936	345
Contract Hydro	255	151	234	141
Total Hydro	1191	497	1170	486
Total Thermal	298	162	741 *	470 *
Contracts (Net)	259	203	262	68
Misc. Resources	8	3	8	3
Total Resources	1756	865	2181	1027

In addition, the area is facing future long-term energy deficiencies. The Pacific Northwest Utilities Conference Commitee annually publishes a forecast of loads and resources for an eleven-year period. The "West Group Forecast" includes the west group portion of Northwest Power Pool and includes states of Washington, Oregon and north Idaho. The 1980 forecast reveals continued alarming trends. It indicates energy deficiencies, based on adverse water conditions, in each year of the forecast, and in five of the eleven years the deficiencies are greater than 3000 average mw; and in every year the deficiencies are greater than the relief available from the region's interruptible customers. Despite a reduction in load growth from previous forecasts, the delays encountered in bringing new plants on line have increased the probability of shortages.

With these unique operating characteristics in mind, the following comments are offered in response to the request for information found on pages 5 -7 of the April 11, 1980, publication signed by Howard F. Perry, Acting Assistant Administrator for Electric Utility Systems, Economic Regulatory Administration:

1. The Company's Northeast Combustion Turbine (66 mw capacity) which was an interim facility has been classified as an existing combustion-turbine facility, with a five-year exemption to operate on natural gas. The impact on the Company will be particularly severe when this exemption expires. Even if planned and under construction facilities are completed on schedule, the occurrence of poor hydro conditions will require the operation of these machines. At the present time gas is the more economic and more abundant fuel available, and poor water conditions will almost certainly require more than 1500 hours of operation, even on the more expensive distillate fuel. Likewise, the Fuels Use Act places considerable doubt upon the Company's ability to construct additional peaking-type resources, to be used for emergency energy production, even though such resources will always be required, particularly in an area as highly dependent on variable hydro resources as the one in which the Company operates.

2. At the present time, the Company owns 15 percent of the 1400-mw Centralia coal-fired plant now in operation in Centralia, Washington. The Company has also 15 percent ownership of the two 700-mw Colstrip units (near Colstrip, Montana) which are under construction. In addition, the Company is proposing to sponsor a 500-mw coal-fired station in the vicinity of Creston, Washington with an ultimate site capacity of 2000 mw. The Company operates no oil-fired or gas-fired power generation boilers and, hence conversion to coal is not an alternative available to the Company to reduce its consumption of oil and gas.

3. The Company has been seriously investigating the potential of utilizing wood waste as an electric energy resource. Thorough engineering feasibility studies and environmental impact studies have been completed to construct a nominal 40-mw wood waste-fired electric generation station in the vicinity of Kettle Falls, Washington. Although the overall economics for this type of project are favorable, recent economic conditions have restricted the ability of the Company to raise capital. For this reason, the Company has delayed further action on the project until mid-1981.

The Company is also actively pursuing and reviewing all potential hydro sites, large and small, in our service area. State and federal studies have identified a large potential for this resource; however, these studies evaluate only the potential of additional energy production without regard for environmental and economic feasibility. In reality, the Company has only a very limited realizable hydro potential left on its system. Utilization of wind and solar energy is promising but not in sufficient quantities that could eliminate the area deficiencies and the need for base load thermal plants.

4. With respect to cogeneration, numerous potential arrangements exist within the Company's service area. The Company has conducted a detailed survey to determine the technical potential of cogeneration resources within the Company's service area. At the present time, the Company is purchasing electricity generated from one industrial customer totaling approximately four megawatts. The Company believes that cogeneration is

a viable energy resource to the Company's system; however, in most cases, cogeneration resources cannot be considered reliable peaking resources and, thus they are no substitute for the Company's combustion turbine capacity.

5. The Washington Water Power Company has applied for only one exemption under the Act which resulted in a five-year operating exemption to utilize natural gas at the Northeast Combustion Turbine site. In the future, natural gas will likely remain the most economic choice for the Company's emergency peaking turbines. For this reason, the Fuels Use Act will result in economic penalties with respect to future peaking resource additions, and for the Northeast combustion-turbines after the five-year exemption expires.

6. The utilities in the Northwest Power Pool have a long history of cooperative planning and shared ownership of large thermal generating stations. In the past, the problem has not been in gaining participation status in these projects, but rather in getting the projects themselves licensed and constructed. For example, Colstrip Units 3 and 4 are scheduled for commercial operation more than five years later than originally planned. Likewise, it now appears that the Washington Public Power Supply System nuclear project WNP #3 (of which the Company owns five percent) will also be delayed more than five years from the original schedule. The Company is also participating 10% in the Skagit nuclear project sponsored by Puget Sound Power & Light. This project, due to siting problems, has been delayed nine years from the original date of operation.

   Construction of transmission facilities has also been a problem. It now appears that the critical path for delivery of power from the Colstrip units will be the construction of transmission from the projects to the west. Likewise, the generation output of the Jim Bridger station owned by Pacific Power & Light Company and Idaho Power Company located in Wyoming is presently limited because of the delayed construction of the Midpoint-Malin transmission line. (The Jim Bridger project, at times, has surplus thermal energy available for purchase at economic rates to The Washington Water Power Company.)

7. In the opinion of The Washington Water Power Company, the most direct way to reduce utility dependence upon oil and gas is to promote the planning, licensing and construction of new facilities which make use of other fuels (coal, nuclear, wood, etc.). Likewise, more efficient utilization of present oil and gas consumption should be promoted through encouragement of cogeneration and combined-cycle resource additions. All of these alternatives are much more capital-intensive than the installation of simple-cycle emergency capacity combustion turbines which operate on conventional liquid petroleum and natural gas fuels. In order to shift the resource base away from this type of facility, all utilities will require timely rate relief, (both at the State and Federal level), and reforms in the ratemaking process which will relieve some of the financial burden of constructing large base-load and unconventional resource additions which do not consume scarce fossil fuels. In addition, a method to expedite the siting and licensing process for large base load thermal units, that would eliminate the need for oil and gas generation, would be most beneficial.

LEIGHTON AND SHERLINE
SUITE 803
1701 K STREET N.W.
WASHINGTON, D. C. 20006

May 28, 1980

Small Utilities Study
Office of Utility Systems
U.S. Department of Energy
Economic Regulatory Administration
Room 4002
2000 M Street, N.W.
Washington, D.C. 20461

Gentlemen:

On behalf of The Montana Power Company, and in response to your request for comments, executed April 11, 1980, and further amended, we file herewith, one signed and two xeroxed copies of its views and comments.

Yours very truly,

LEIGHTON AND SHERLINE

Lee S. Sherline

by Lee S. Sherline

LSS:er
Enclosures

UNITED STATES OF AMERICA
ECONOMIC REGULATORY ADMINISTRATION
DEPARTMENT OF ENERGY

Requests for Information; Concerning)
Report to Congress on the Study)
of Compliance Problems of Small)
Electric Utility Systems with the)
Powerplant and Industrial Fuel Use)
Act of 1978)
)

COMMENTS OF THE MONTANA POWER COMPANY

On April 17, 1980, the Department of Energy, Economic Regulatory Administration issued a Request for Information. That request stated that the Department of Energy was inviting interested persons to provide information, views, and comments regarding a study of the problems of compliance with the Powerplant and Industrial Fuel Use Act of 1978 ("FUA") experienced by electric utilities with a total system generating capacity of less than 2,000 MW. The Department of Energy stated that the study would concentrate on the special difficulties that utilities may face in complying with the FUA prohibitions against the use of natural gas and/or oil that are a consequence of their small size, and will identify possible technical, regulatory, or legislative remedies. 45 Fed. Reg. 26117.

In response to the Department of Energy's Request for Comments, The Montana Power Company ("MPC) hereby submits its views, comments, and suggestions regarding legislative remedies to the FUA. The name, title, mailing address and telephone number of the person to whom communications concerning these comments should be submitted is as follows:

Robert Labrie
Vice President, Engineering
& Technology
The Montana Power Company
40 East Broadway
Butte, MT 59701
(406) 723-5421

MPC is an investor-owned utility which serves customers at retail and wholesale in the State of Montana. MPC's fully integrated and interconnected electric system extends through the western two-thirds of the State of Montana, and serves more than 217,000 retail customers, and several rural electric cooperatives and one Indian Irrigation Project at wholesale.

MPC has an installed generating capacity on its system totalling 1100 MW, consisting of 520 MW hydro electric, 576 MW steam, and 4.7 MW of internal combustion. MPC is also the sponsor of a new steam-electric generating facility involving the construction of twin 700 MW units by six participating utility systems. MPC's ownership share of the new facility will be 30%. This new facility scheduled for commercial operation in 1984 will add 420 MW to MPC's system, bringing the total capacity of 1520 MW.

MPC welcomes an opportunity to comment on the effects of FUA on our system and operation in an effort to identify particular problems in complying with the Act. While the problems MPC encounters with the FUA are not necessarily a consequence of its relative small size (under 2000 MW), the potential economic impact and placement of constraints on MPC's operation of available resources could be considerable.

The effect of the FUA will be most obvious in the operation of MPC's Frank Bird steam electric generating plant ("Bird"). The Bird unit was installed on MPC's system with a 66 MW peak capacity to meet the need for peak capacity and energy during periods of adverse or critical stream flows when adequate capacity and energy were not available out of MPC's hydroelectric system. The Bird unit, which is capable of being fired on oil or natural gas, has been operated over the past 25 years in a manner optimizing the efficiency of MPC's available resources. Under the various definitions of the FUA, Bird was operated during six of those years as a base-load plant, during five of those years as an intermediate-load plant, and during the remaining 14 years as a peak-load plant. The fluctuation in annual generation out of Bird is a function of the need for resources in Montana and the Western United States largely as determined by the availability of water for hydroelectric generation.

The FUA extends the following alternatives to MPC in bringing the operation of Bird into compliance with the Act:

1. To operate until January 1, 1990 on a mixture of natural gas to oil of about 65% to 35% respectively, and thereafter on a peak-load plant basis (under 1500 hrs./yr.).

2. Obtain a permanent exemption from the prohibition of the Act.

The first alternative leaves much to be desired, in that the required mixture of gas to oil completely ignores the relative economies to be enjoyed with one fuel over the other. It also ignores the relative availability of one fuel over the other. (The economics would normally be a function of availability, but that is not necessarily the case with gas and oil.) The intent of the FUA in dealing with existing facilities was to disallow the increased use of natural gas between the effective date of the Act and 1990. However, this effort to minimize the drain on natural gas resources by large users and to extend availability of supplies for space heating purposes actually has the potential to cause an unnecessarily large drain on petroleum, also a critical natural resource, the use of which has a profound effect on national economic stability.

Absent the prohibitions of the FUA, the use of fuel in a facility such as Bird would be dictated by the economies of supply and would thereby most likely be in the national best interest.

Since Bird has the ability to fire on either gas or oil, and because MPC has significant surpluses of "take-or-pay" Canadian natural gas, it prefers, at the present time, to fire Bird on gas. This is an economic operation of Bird for MPC and at the same time tends to reduce consumption of precious petroleum when it is in the nation's best interest to reduce petroleum dependency. Absent a temporary exemption from the prohibitions of the FUA, MPC would be forced to burn oil and gas to its and the nation's detriment. The requirement of the FUA to burn no more gas in existing facilities than in the test years should be altered to recognize situations such as that affecting the operation of Bird.

If the operation of Bird were confined to the equivalent of 1500 hours per year at full capacity, we could anticipate periods when Bird energy would be required to meet load and would be unavailable due to the 1500-hour restriction. This would force MPC to purchase alternative resources from other systems, perhaps at much higher cost than Bird, or in anticipation of such a circumstance, to install additional oil or gas burning combustion turbines to supplement, to the extent necessary, the operation of Bird. Inherent in compliance with the 1500 hour operating restriction, then, are higher costs to ratepayers for purchased energy, additional capital investment, and possibly increased consumption of high cost gas and oil.

The FUA does nothing whatsoever to decrease the demand for electric energy, but can significantly reduce the available supply of electric energy. If the load is to be served, the reduction in energy supply available out of existing resources will have to be offset by a corresponding increase in new higher cost generation facilities, at the expense of the consumer.

Since the operation of Bird would be restricted to 1500 hours per year, it would be imprudent to make Bird production available to other utilities when its production was not required by MPC loads, and thereby sacrifice future availability for MPC loads. This restriction therefore "robs" the western interconnected region of possibly critically needed resources. The requirements of the FUA should be altered to recognize and compensate for this effect.

The second alternative, to obtain a permanent exemption, is the only prudent choice for MPC in dealing with the effects of the FUA on the operation of Bird. This alternative is not without its problems, however. The most expeditious and least costly exemption would be as a peak-load power plant; but as discussed above, this exemption severly restricts the operation, and therefore the value, of Bird as a dependable resource. In addition, it would have to be shown that the conversion of Bird to coal is not technically and/or economically feasible. The process of establishing technical and economic infeasibility imposes unrealistic tests of feasibility on the applicant for exemption, and represents the need for very costly comprehensive studies. Furthermore, if coal-capability is established, there will be an inherent loss of valuable generation capability resulting from the conversion, and a direct confrontation with the concerns for the quality of the environment. Because of the fact that responsible Federal Agencies seem to be at cross-purposes with each other, the utility in some cases appears to be in a "Catch 22" where conversion to coal must be accomplished to continue plant operation under the FUA, but where such a conversion would violate air quality degradation standards or require uneconomic purchases of offsets, and thereby preclude the conversion and further operation.

We hope to find the proper vehicle for a permanent exemption from the prohibitions of the FUA for Bird, but the proper vehicle is not easily identified among the regulatory alternatives, and in any case, will require a signficant expenditure of monies.

We certainly don't disagree with the need to encourage a reduction in the national dependence on natural gas and petroleum, but the necessary reductions must not be imposed arbitrarily without consideration for the economic effects produced by the potentially substantial loss of existing generating capability. This loss of capability will result in loss of American worker productivity and therefore impose deleterious effects on the national economy of greater import than the consumption of gas or oil.

To the maximum extent possible, the requirements of the FUA should be adjusted to maintain the balance between resource requirements and resource availability. The American economy does not occupy the enviable position of being able to sacrifice badly needed electric energy resources at a time when the regulatory atmosphere disallows the timely replacement of those resources, which represent a drain on scarce fuels, with other resources which operate independent of scarce fuels. The replacement process will take time and changes recognizing this fact must be made in implementation of the FUA.

(Interestingly, the orderly replacement of oil and gas-fired resources would likely take place over a reasonable period of time without the influence of the FUA. The cost of running these resources is rendering them economically obsolete, and utilities must, of their own accord, be developing alternate fuel resources. The FUA may speed the process, but otherwise, simply adds chaos to changes that would come about anyway as a natural effect of economics.)

In the establishment of new base-load coal-fired resources such as Colstrip Units #3 and #4 (sponsored by MPC-referenced earlier), it is necessary to install an auxiliary boiler for plant start-up, and perhaps to install a separate heating boiler for seasonal use when the plant is off. The FUA appears to contain restrictions which would disallow the use of gas or oil in the Colstrip Units #3 and #4 auxiliary boiler, even though the boiler is used only occasionally for start-up purposes when both units have been off-line. A quick response rate is essential for an auxiliary boiler and can only be assured by use of liquid fuels rather than solid fuels. In addition, the auxiliary boiler fired on gas or oil can be smaller in size requiring less capital investment, does not in itself frustrate satisfaction of environmental requirements, and accounts for increased plant availability.

In our concern that the FUA restricts use of oil in the auxiliary boiler in Colstrip Units #3 and #4 is properly founded, the FUA tends to add considerably to the difficulty and frustration of getting base-load coal-fired resources established to replace some of the need for oil and gas-fired resources, and should be changed to allow the use of oil or gas in auxiliary and heating boilers in coal-fired generating units.

Respectfully submitted,

James F. Walsh

JAMES F. WALSH
Attorney for
The Montana Power Company
40 East Broadway
Butte, MT 59701

Dated: May 23, 1980

NEW MEXICO ELECTRIC SERVICE COMPANY
P. O. BOX 920
HOBBS, NEW MEXICO. 88240

J. D. REED
PRESIDENT

May 30, 1980

Mr. John H. Williams
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Williams:

This is in response to Mr. Starr's letter of May 22, 1980 and our telephone conversation of yesterday.

Our Company has two generating units: a 118 megawatt gas fired steam turbine and a 66 megawatt gas combustion turbine. The steam turbine is approximately thirteen years old and the gas turbine approximately four years old. We are presently interconnected with Southwestern Public Service Company.

We have recently had a study made by an outside engineering firm which considered our options for a future power supply. This study indicates that after the year 1985 we will be able to purchase our entire power requirement at a cost less than our projected fuel cost. This conclusion is based on gas costing twice as much per MMBTU as coal in 1985.

We are currently negotiating with Southwestern Public Service Company for the purchase of power and the use of our two generators with their system through 1990. After 1990 we may hopefully obtain a variance and operate these machines further for peaking and intermediate use.

I enjoyed talking with you and will appreciate a copy of your study when available.

Yours very truly,

JDR/cl

PSNH PUBLIC SERVICE
Company of New Hampshire

June 2, 1980

Mr. Alan W. Starr
Chief, Source Technology & Economic Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Starr:

Thank you for your recent letter that we received on May 26th in regard to problems small utilities are facing in complying with the Fuel Use Act of 1978.

Some of the problems that we forsee for small utilities converting oil burning generating units to coal burning are:

1. Meeting capacity requirements with generating units not available during conversion period.

2(a)Land areas for coal storage and for ash and sludge disposal.

(b)Ability to finance the capital costs of the conversion and continue to finance all other construction projects especially non oil generating stations at the same time.

Very truly yours,

R. E. Closson

R. E. Closson
Vice President

REC:ddj

cc: W. A. Harvey

1000 Elm St., P.O. Box 330 Manchester, NH 03105 Telephone 603/669-4000

The Electric Company

El Paso Electric Company
P.O. Box 982
El Paso, Texas 79960
(915) 543-5711

June 5, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street, N.W.
Washington, D. C. 20461

Gentlemen:

The following comments on the pending "Report to Congress on the Study of Compliance Problems of Small Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978" are presented by the El Paso Electric Company (EPE) of El Paso, Texas.

El Paso Electric Company is a small investor-owned electric utility having a total system generating capacity of less than 1,000 MW that is substantially affected by the rules and regulations implementing the Powerplant and Industrial Fuel Use Act of 1978, also known as the "FUA."

The FUA from its inception has been superfluous and counterproductive. In addition, it has imposed increased regulatory burdens on U.S. industry, especially electric utilities.

It was initially enacted to promote the then national goal of conserving natural gas and fuel oil in electric utility boilers by having them use or convert to coal. The problem is that many boilers, especially in small utilities such as EPE, were never designed for coal use nor were they designed to be retrofitted for coal conversion. Also, the only feasible alternative to natural gas firing in these boilers was conversion to fuel oil. However, recent world events have created a scenario where the national goal is now to conserve fuel oil and to reduce the Nation's dependence on foreign sources of the oil. Ironically, the FUA, as written and implemented, will increase and not decrease our Nation's dependence on foreign sources of petroleum since every 1,000 Mcf of natural gas withheld from electric utilities and not displaced by coal or nuclear will result in an additional usage of approximately 175 barrels of oil.

Now, EPE finds itself in this dilemma. At present, its generation base is composed mainly of gas and oil-fired boilers which are subject to Title III of the FUA. EPE must then operate these existing boilers with the least expensive fuel to meet its generating requirements until such time that its nuclear and coal units come on line. At present, the most efficient and economical fuel is natural gas. Fortunately, the DOE has recognized this fact and has provided utilities with a regulation allowing them to maximize use of this fuel. The regulation provides for Special Temporary Public Interest Exemptions (STPIE) which are available under Title III, Subtitle B, Section 311(e) of the FUA. Unfortunately, this exemption is only a short-term solution with a maximum effective period of five years from the date the exemption is granted. Also, the documentation required to keep the exemption in force is burdensome. A systemwide fuel conservation plan covering production and end-use conservation measures is required which places a further load on small utility staffs already overladen with other regulatory requirements. This fuel conservation plan is uncalled for and at a minimum duplicates the conservation requirements in the Public Utility Regulatory Policies Act (PURPA) and the National Energy Conservation Policy Act (NECPA). And, as stated before, the STPIE is short-lived, thereby exposing those generating units covered by the exemption to the very restrictive rules of the FUA.

In an effort to prepare for the forementioned problem, EPE looked to other exemptions available under the FUA as means to comply with the FUA and to continue meeting its generating requirements in the most cost-effective manner. However, due to the exhaustive documentation and restrictive qualifications required by the other exemptions, the Company has chosen to file a System Compliance Option Plan (SCOP) available under Title V of the FUA. Unfortunately, the SCOP is not without problems. It too requires a fuel conservation plan which is superfluous, costly and counterproductive to EPE and its customers. The major problems, however, are that:

(i) EPE is forced to commit itself in 1980 to a set schedule of reduced gas usage which, if present gas supply trends continue, will require it to burn more expensive and less available fuel oil, and

(ii) EPE and other small utilities will have to prepare themselves to face a drastic reduction in their gas availability in 1990. Even though a program of reduced gas usage is feasible, the proposed 80% decrease in 1990 of gas use allowed will be economically catastrophic in that no small utility, including EPE, will have the necessary financial and regulatory commission backing to have sufficient nuclear and coal generation base units on line to help offset the decreased gas supply. This reduction in gas allowed will force the consumption of even greater amounts of fuel oil. EPE estimates that an average of 2,900,000 additional barrels of fuel oil will have to be burned per year in order to comply with the 1990 and 1995 requirements of the SCOP. Also, in terms of money, EPE estimates that its total operating costs will be increased an average of $247,400,000 per year (approximately $47,660,000 per year in 1980 dollars) due to the forementioned requirements.

In general, EPE believes that the present FUA and the available avenues of complying will have an adverse effect not only on EPE and its customers but also on the Nation's industrial effort as a whole. Therefore, the FUA must be viewed as a counterproductive measure and not in the best interests of the Nation.

Sincerely,

Evern Wall

Evern R. Wall
President

Sierra Pacific Power Company

LEGAL DEPARTMENT

June 5, 1980

Small Utility Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street, N.W.
Washington D. C. 20461

Gentlemen:

Enclosed are the original and six copies of Sierra Pacific Power Company's comments pursuant to Section 744 of the Powerplant and Industrial Fuel Use Act of 1978.

Very truly yours,

Patrick Kinney

Patrick T. Kinney
Staff Attorney

P. O. BOX 10100/RENO, NEVADA 89510/TELEPHONE 702/789-4225

DEPARTMENT OF ENERGY

BEFORE THE ECONOMIC REGULATORY ADMINISTRATION

Report to Congress on the Study of
Compliance Problems of Small Electric
Utility Systems with the Powerplant
and Industrial Fuel Use Act of 1978.
____/

SIERRA PACIFIC POWER COMPANY'S COMMENTS PURSUANT TO SECTION 744 OF THE POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

Sierra Pacific Power Company is a public utility engaged in operations in the States of Nevada and California. As a utility with a total system generating capacity of less than 2000 MW, Sierra Pacific is a utility subject to the study of the Economic Regulatory Administration of the Department of Energy in its report to Congress pursuant to Section 744 of the Fuel Use Act.

Sierra Pacific has had several contacts with Department of Energy personnel concerning use of Sierra Pacific in a case study for small utilities under Section 744 of the Act. In these previous conversations, Sierra Pacific has communicated to the Department of Energy personnel its potential problems of compliance with the Act.

Because a small utility will have substantially the same workload as a large utility, but does not have near the staff size of a large utility, federal legislation such as the Fuel Use Act presents great problems to the small utility. In the case of the Fuel Use Act, one of the biggest problems, at least for Sierra Pacific, is determining what actual effect the Act will have. This problem was exacerbated in the case of the FUA by regulations which deal with plants on a case-by-case basis.

For a small utility such as Sierra Pacific to have substantial capital expenditures in converting an existing powerplant to an alternate fuel, when the result is a net loss in capacity over the life of the plant and the total loss of capacity during the time of conversion, is very unattractive. This problem is made worse for Sierra Pacific by the tremendous growth within its service territory. What would help Sierra Pacific immensely in avoidance of these high capital costs would be some sort of federal aid as proposed in legislation now before the United States Congress amending the Fuel Use Act and the implementation of the oil Backout legislation. Otherwise, the goal of national energy policy to reduce dependence upon foreign oil will be achieved at the expense of ratepayers of small utilities.

Sierra Pacific was sufficiently farsighted to begin planning coal-fired plants several years ago, and the first of these plants which is owned jointly by Sierra Pacific and Idaho Power Company, will be on line in the Fall of 1981. Furthermore, Sierra Pacific is making substantial efforts in developing the geothermal potential of its service area. Sierra Pacific has also applied to the Department of Energy for a grant to determine the feasibility of converting one of its oil and natural gas fired units to a solar-fossil fuel hybrid unit.

One area with which Sierra Pacific is concerned is the potential for conflict between the nation's energy economic and environmental policies. A small utility is presently caught between the need to provide its service at the lowest possible price, the desire to reduce dependence on foreign energy souces, and the desire to produce electricity with minimal effects on the environment. What we feel is necessary is that any future amendments to the Fuel Use Act and environmental acts provide for a means of coordinating regulatory efforts to resolve these conflicts.

SIERRA PACIFIC POWER COMPANY

By Patrick T. Kinney
Patrick T. Kinney
Staff Attorney
100 East Moana Lane
P.O. Box 10100
Reno, Nevada 89520
Tel: (702)789-4360

June 5, 1980

SYSTEM COMPANY

EUA Service Corporation

99 High Street, Suite 2830, Boston, Massachusetts 02110 Telephone (617) 357-9590
Address all correspondence to P.O. Box 2333, Boston, Massachusetts 02107

June 5, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Starr:

Your letter of May 22, 1980 requested our ideas as to how small utilities can be assisted in gaining compliance with the Power Plant and Industrial Fuel Use Act of 1978 (FUA). Small utilities are not much different from large ones - they face the same financial problems, require the same generating mix, need expertise in making load forecasts, and are faced with the same barrage of paperwork and regulation. The difference is in having the manpower to solve these problems. It just isn't there without spending a disproportionately large amount of money to do these necessary functions. The FUA certainly exacerbates EUA's operational and financial difficulties.

This leads me to your letter and our proposals to make the FUA less onerous and more useful to the nation. My comments are not necessarily addressed to aiding just the small utilities, but all because many of the problems are common.

1. Understanding the regulations and their intent.
    a. Provide a clear and concise description of what is required of the utilities.
    b. What are the alternatives, if any.
    c. Organize meetings at several convenient locations around the country where the Act is explained and actions required provided. Have a discussion period.
2. Assist in promoting joint-ownership agreements. We are fortunate in New England in having had such arrangements for a number of years, but other parts of the country may not be so fortunate. A single small utility does not have the physical or financial resources to construct, alone, the large nuclear- or coal-fired units which are being constructed. Joint ownership of 5-25% shares provides such means. You could furnish typical JO agreements

and possibly assist in the organization or participation in such projects. The "biggies" are notoriously shy about sponsoring groups of small entities under the umbrella of their private developments. Why should they?

3. The environmental criteria and rules for conversion are not clear. There is disagreement among governmental departments. Spell out what can and cannot be done.

4. Provide funds for studies and consultants' assistance at plants where coal conversions are being considered. Small utilities usually do not have the in-house expertise to make such studies, and outside assistance is quite costly.

5. Small (and even larger) utilities are very reluctant to install the exotic types of generation, such as solar, wood burning, gassifiers, etc., until these new technologies are established. Again, the financial and physical resources needed are large in proportion to the smalls' size. In addition, there is the unknown factor whether the regulators will permit full recovery of costs if the project should fail - or even if successful. So far, the federal government has been unable to guarantee such recovery, while the state regulations are fickle in their treatment of such projects.

6. The number one problem area is raising capital. The smaller utilities probably are harder pressed, but the problem is common to all utilities. A project such as coal conversion, might, on paper, show a rich pay-off; but how does a utility proceed if it cannot raise the money for construction?

Mr. Starr, I thank you for providing us an opportunity to air our views about the smaller utilities' problems in implementing the FUA's intent. One further suggestion, a conference of executives from the small utilities, where a verbal exchange of views could take place, could provide you with a wealth of ideas.

Yours very truly,

J. F. G. Eichorn

J. F. G. Eichorn, Jr.
President

JBG:sab

New England Gas and Electric Association
An investor-owned, taxpaying utility system
POST OFFICE BOX 190 • CAMBRIDGE, MASSACHUSETTS 02139 • AREA CODE 617 864-3100

OFFICE OF
THE PRESIDENT

June 5, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and
Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Starr:

The following comments are in response to your letter requesting background data on problems we, as a small utility system, are facing in complying with the Powerplant and Industrial Fuel Use Act of 1978 (FUA).

As we understand FUA, we are not directly affected in any significant way by the portions of the law which prohibit use of petroleum and natural gas in new power plants as we have none planned or under construction, or by the sections which prohibit or limit the use of natural gas in certain existing power plants. However, we could be significantly impacted by those provisions of FUA which allow the Secretary of Energy to prohibit, by order, the use of petroleum in existing power plants. At present, our System's Canal Unit One has been listed as a potential candidate for conversion by the Department of Energy (DOE). In response to your request, I will concentrate on describing some of the problems we would face in complying with any mandatory prohibition of the use of oil to fire this unit.

First, some background data is in order. New England Gas and Electric Association (NEGEA) is a small combination electric-gas utility holding company, operating completely within the state of Massachusetts. We have four operating utility subsidiaries, one selling natural gas at retail, one straight electric distribution company, a combination electric-gas distribution company, and a wholesale electric generating company. Our electric operations cover 41 cities and towns in eastern and southeastern Massachusetts, and we serve over 260,000 customers. Our own system generation totals 1,087 MW, of which 864 MW is represented by two oil-fired units located at the eastern end of the Cape Cod Canal. It is the first of these two units, representing 572 MW, which has been listed as a potential conversion candidate in the DOE review of units impacted by FUA. All of the other units owned by our system, which are oil or diesel, are of either an age, size or design to exclude them from any consideration of possible conversion to coal.

The name "New England Gas and Electric Association" means the trustees for the time being (as trustees but not individually) under a Declaration of Trust dated December 31, 1926, as amended, which is hereby referred to, and a copy of which has been filed with the Secretary of The Commonwealth of Massachusetts. Any agreement, obligation or liability made, entered into or incurred by or on behalf of said Association binds only the trust estate, and no shareholder, director, trustee, officer or agent assumes, or shall be held to, any liability by reason thereof.

Canal Unit One represents over half of our system's owned generation. 429 MW of its capacity has been sold under life of unit contracts to three neighboring utility systems. This unit was planned, constructed and designed during the mid-1960's as a baseload, boiler (furnace volume) designed for dual fuel burning capability, at an original cost of $56 million (currently $65 million). This unit has an estimated useful life of 28 years, and commenced operation in 1968. It has been rated as the most efficient oil-fired generating station in the United States since 1973. This unit burns approximately five million barrels of residual fuel oil annually, and is currently dispatched by the New England Power Pool (NEPOOL) on a base loaded basis. At the time this unit was constructed, foreign residual oil was available at under $2.00 per barrel and was a more desirable fuel environmentally in the heavily-populated northeast corridor of the United States. As a result of these conditions, even though the boiler had technical dual fuel capability, no investment was made then or since applicable to coal.

Current studies show that approximately $200-$225 million (in 1980 $) will be required to convert this unit to coal. If scrubbers are required, an additional $75 million would be spent. These expenditures include all coal handling and storage facilities, ash handling and removal systems and major changes to our berthing basin to handle coal barges. Also major modifications will be required to both the boiler and precipitators because of both a change in the technology or "State of the Art" over the past 15 years as well as environmental requirements. This amount (potentially $300 million) represents over five times the original investment, represents almost ten times our current unrecovered cost in the unit and is in excess of 300% of the existing capitalization of Canal and over 80% of the present consolidated capitalization of the NEGEA System. In addition, this expenditure would be required during a five-year period in which we are committed to $350 million for new construction, of which over half relates to new electric generating capacity in joint-owned units (all nuclear).

We agree that the reduction of our country's use of and reliance on foreign sources of supply of oil or any other major source of energy is in the best interest of national security. However, we believe strongly that it is not sensible for Congress to mandate that coal conversions take place without reviewing whether or not it is financially possible for the companies affected to accomplish this during the period mandated by the present law.

Further, it appears that the northeast region of the country is targeted for the major amount of this conversion activity. The energy consumers in this region are already suffering from the high cost of oil used in generating electricity, for heating their homes and operating their vehicles. It does not seem fair for the total additional costs of conversion to now be inflicted on this region when these units were constructed in good faith during a period when cheap foreign oil was readily available and its use allowed us to actually preserve our own domestic oil supply.

We are in the process of having a complete study performed by outside consultants which will document the previously described costs to accomplish this conversion. We are also studying our future generation requirements which show, based on a minimal load growth scenario, that our system will be 150-200 megawatts deficient by the early 1990's. All of the planning and coordination of future power needs in New England is now being accomplished through NEPOOL on a New England-wide basis. Presently only three major generating units are under construction which are scheduled to be completed before 1990.

We believe that a better solution, instead of converting Canal Unit One, which will accomplish much more with the same amount of investment in only a slightly longer time frame would be to start planning now to bring a new 600-megawatt coal-fired unit on line by 1990 at our Canal Plant site. $225-$300 million is a lot of money whether it is provided by the Company, the government or from whatever source. This amount would buy us (in 1980 $) a 1/4 to 1/3 interest in a completely new coal unit - designed from the ground up for coal with all present "state of the art" technology. We anticipate no difficulty in lining up interest in the remaining 2/3 to 3/4 from other members of NEPOOL. This unit would enable the Pool to back off the oil burn from less efficient units presently required to be dispatched and which in all likelihood will never be candidates for conversion to coal.

Further, if the technology of coal-oil slurry or coal liquefaction improves to a commercially acceptable level, Canal Unit One could utilize this technology. Coupled with a new coal-fired unit the incremental cost of these technologies would be minimal, with all coal handling equipment in place with the construction of a new coal-fired unit.

In addition, as the heavier financing costs of a new unit would be incurred in the period after 1985, we should be able to finance our 1/4 to 1/3 interest in a new unit conventionally without any government help - grants, loans or otherwise. Presently it is questionable that without almost 100% government financing during the period 1980 to 1985 that we could accomplish the financing which would be required to convert Canal Unit One.

The bottom line is that we do not believe that an expenditure of $225-$300 million can be justified on a unit which is approaching half life and which will be close to two-thirds life by the time all modifications would be in place. Further, this expenditure would not provide any additional generating capacity for New England, in fact it will take away up to 20 megawatts for additional station service. It is a much better long-range answer to build new, non oil-fired generation, environmentally planned and use these new plants to "back-out" oil currently burned in old, less-efficient units. This takes care of both the oil and capacity problems as we plan for the rest of this century.

Thank you for this opportunity to respond to problems we see in complying with the FUA. I am hopeful that this has been responsive to your request. If there are any questions or if there is anything further we can add to this material, please do not hesitate to call me at (617) 864-3100, or if I am not available, contact our System Executive Vice President-Electric Operations, Jeremiah V. Donovan.

Sincerely,

Gerald E. Anderson

NE
GEA:vc

IOWA-ILLINOIS GAS AND ELECTRIC COMPANY
DAVENPORT, IOWA

June 4, 1980

Mr. Howard F. Perry
Acting Assistant Administrator of
Utility Systems
Economic Regulatory Administration
Small Utilities Study,
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street, N.W.
Washington, D. C. 20461

Dear Mr. Perry:

Re Economic Regulatory Administration Report to Congress on the Study of Compliance Problems of Small Electric Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978

Iowa-Illinois Gas and Electric Company (Company) herewith submits its comments related to Problems of Small Utilities with the Powerplant and Industrial Fuel Use Act as issued April 11, 1980 (45 F.R. 26117, 4/17/80) by the Economic Regulatory Administration inviting comment by May 23, 1980, extended to June 6, 1980 (letter of Alan W. Starr).

The names, titles, mailing addresses, and telephone numbers of the persons to whom communications concerning the proposal should be addressed are:

W. C. Morrison, Superintendent
Governmental Relations Division
Iowa-Illinois Gas and Electric Company
206 East Second Street, P. O. Box 4350
Davenport, Iowa 52808
Telephone: Area Code 319 326-7097

Edward J. Hartman,
Vice President-General Counsel
Iowa-Illinois Gas and Electric Company
206 East Second Street, P. O. Box 4350
Davenport, Iowa 52808
Telephone: Area Code 319 326-7334.

POST OFFICE BOX 4350, 206 EAST SECOND STREET, DAVENPORT, IOWA 52808

I. Interest

Company is an investor-owned utility engaged in the generation, transmission, and distribution of electricity, both at wholesale and retail, providing electric service to customers in the states of Iowa and Illinois, in and around the prinicipal communities of Rock Island, Moline and East Moline, Illinois and Davenport, Bettendorf, Iowa City and Fort Dodge, Iowa, and the surrounding suburban and rural areas.

Company is subject to the provisions of the Powerplant and Industrial Fuel Use Act of 1978 (FUA) and the regulations developed by the Economic Regulatory Administration (ERA) to implement the Act. Company requested and was granted by the ERA a Temporary Public Interest Exemption for its Moline and Coralville Generating Stations under Section 311E of the FUA on May 12, 1980. The Company will also be subject to rulings that may result from the implementation of the FUA from proceedings before the Iowa State Commerce Commission and the Illinois Commerce Commission under whose respective jurisdiction the Company renders electric service at retail.

II. Comments

The primary thrust of the Powerplant and Industrial Fuel Use Act is to eliminate, over a period of time, the use of natural gas or oil as the primary energy source by existing electric power plants. The regulations which have been developed to implement the FUA are, however, burdensome to all and present requirements that some small operators will find impossible to meet.

The presently effective regulations cover all electric utility plants regardless of size, fuel availability or mode of operation. This broad approach does not, among other things, recognize or appreciate the uniqueness of peak load plants. These plants are not necessarily operated by steam produced by boilers. Further, peaking plants operate only a small part of the year when the peak electric load occurs and during emergencies - usually not more than 1 to 1-1/2 months of cumulative operation. Economics require utilities to use low capital intensity peaking plants to carry the load during these short high load periods. At present there is no technologically feasible method of operating gas or oil fired turbines and internal combustion engines with fuels other than natural gas or fuel oil.

The economics of meeting environmental regulations prohibits (1) the use of coal in small plants that currently use coal and (2) the conversion of small plants from oil or gas to coal.

Company is a participant in the North Dakota Synthetic Fuels Feasibility Study which will investigate the feasibility of providing synthetic fuel from lignite in hopes that in future years this synthetic fuel will become a viable source of energy for gas fired turbines and internal combustion engines used as peaking plants. Company is also participating in a feasibility study for the use of urban waste as a fuel, but such waste cannot be used in existing peaking plants nor would it be feasible to consider it as fuel for a plant that only operated for a short period each year. Even if either or both of these projects prove feasible there is doubt that consumption of gas or oil can be eliminated for the peak load plants in the foreseeable future.

Provisions are made in the FUA and rules for a broad range of exemptions from the prohibitions of the Act in recognition of the fact that such needs exist. However, the burdens of submitting documented information with an application are compounded by grossly excessive reporting requirements if the exemption is granted. Primarily because of the burdens of developing a system of compliance plan and regular reporting associated with it or of developing the documentation of a fuels decision report, Company chose to request a Temporary Public Interest Exemption to burn natural gas whenever such use would displace fuel oil on certain reserve and peaking units where natural gas and fuel oil are the only available options. It seems obvious, both economically and in the interest of reducing oil imports, that such natural gas should be used when available. Two of three requested exemptions were granted eventually; however, Company is required to report a conservation plan and progress toward accomplishing the goals of that plan through the period of exemption which appears to serve no useful purpose and may cost more than the price differential between fuel oil and natural gas.

The fuel cost of peak load plants (gas and oil fired turbines and internal combustion engines) is usually more than the fuel cost at other plants on a company's system. Thus, these plants are ordinarily not used unless there is no alternative. Also, in many instances, peak load plants (gas & oil fired turbines and internal combustion engines) are located at load centers, and controlled automatically from a control center, and have access to no fuel other than natural gas or oil. Due to these limiting factors, Company suggests a change in the FUA or implementing regulations to exempt a plant that is operated, for instance, for no more than 1000 hours per year or has a nameplate rating of 20 MW or less. Certainly, the fuel consumed by such exempted facilities would be minimal. Further, such an exemption would reduce the paperwork and problems of both the ERA and operators.

Summary

In Company's situation, economics alone would achieve the goals of Fuel Use Act. Nuclear fueled generation is our lowest cost source of energy, followed by coal, natural gas and fuel oil in that order. The fuels to be conserved are used only when less costly options are not available. The substantial reporting requirements of Fuel Use Act are, therefore, a needless cost to the utility customers.

We appreciate the opportunity to submit these views and comments, and submit an original and five copies for your consideration.

Very truly yours,

W. C. Morrison
Superintendent
Governmental Relations Division
Energy Planning Department

WCM-ks
cc: Secretary
Iowa State Commerce Commission

Secretary
Illinois Commerce Commission

IOWA POWER

IOWA POWER
823 Walnut Street / P.O. Box 657
Des Moines, Iowa 50303
515-281-2385

J. R. Lyon
President

June 5, 1980

Mr. Alan W. Starr
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Starr:

Iowa Power's use of oil and natural gas is limited to existing peaking units. Therefore we have no serious problems in complying with the Fuel Use Act at the present time.

Yours truly,

J. R. Lyon

THE EMPIRE DISTRICT ELECTRIC COMPANY
JOPLIN, MISSOURI 64801

June 5, 1980

A. R. PUFFINBARGER
SENIOR VICE PRESIDENT
PRODUCTION

Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Room 4002, 2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Starr

Pursuant to your letter of May 22 relative to problems that small utilities are facing in complying with the Power Plant and Industrial Fuel Use Act of 1978 (FUA), the following comments are respectfully submitted and may be of interest and of some value to the Department of Energy.

The Empire District Electric Company (the Company) has experienced a steady decline in demand rate of growth in recent years; relatively high increases in demands from 1970 to 1974, moderately increasing demands from 1975 to 1979, with a lesser demand increase anticipated in the period 1980 to 1985. The variance in demand during the decade of the seventies created consistently moving targets for power plant capacity installation. These variances in demand were generally experienced by most all electrical utilities in this time frame. Astronomical increases of plant investment requirements per unit of new capacity were coupled with the relatively high increases in demand in the early seventies, and the lesser demand increases in later years, 1975 to 1979. It should also be noted that the economy of scale differences in dollars per kilowatt installed were substantial in the seventies.

Other factors that made planning difficult for the Company, not necessarily in their order of priority, were as follows:

1. The elimination of Construction Work in Progress (CWIP) from the rate base.
2. Poor regulatory climate with respect to adequate and timely rate relief.
3. Additional investment requirements caused by increased social and political emphasis on environmental concerns.
4. Elimination of the Fuel Adjustment Clause in Missouri.
5. The effect of inflation on fuel, operational expense, and normal construction programs.
6. The Clean Air Act Amendments of 1977.

7. The Reclamation Act of 1978.

8. The Fuel Use Act of 1978.

9. The Natural Gas Policy Act of 1978.

10. The oil embargo of 1974 and the resultant effect on fuel prices, both foreign and domestic.

11. Price elasticity with respect to customer consumption.

12. The adjustment of our customers' priorities relative to the allocation of their dollars spent for the necessities of life.

13. The high cost of money for plant investment, and the subsequent reluctance on the part of some investors to invest in the Company due to an inadequate rate of return on equity.

14. The continually increasing requirements by both State and Federal regulatory authorities on management and staff time.

All of the aforementioned provided a planning atmosphere in the seventies that was continually changing. In essence, what you planned for in one year would not necessarily be the most optimum plan in the succeeding year.

As the Department of Energy realizes, the lead times for coal burning plants increased in the seventies from three years to seven years, and increasing inflationary factors made it almost impossible to predict what the cost of new plant capability would be at the end of this seven year period. Small utilities such as the Company were placed in a position that due to the high cost per unit of new capacity installed, the most optimum program was to look at combustion turbines to cover the required system reserve margins, as well as peaking and emergency capacity when base load capacity was not available.

In the late sixties the Company investigated fuel supplies, determined at that time that there was no real adequate assurance of natural gas supply, and installed a 200 megawatt mine-mouth coal burning plant which was placed in operation in 1970. In 1977 the Company converted, on a voluntary basis, two of its largest and most efficient units (prior to 1970) from natural gas burning to coal burning. In 1978 the Company installed a 90 megawatt light oil burning combustion turbine to meet anticipated future needs at the lowest possible cost, realizing the fuel component per kilowatt-hour would be high but the investment cost per kilowatt would be low. Initial planning on this unit started in 1974.

A second 90 megawatt unit was also planned to go into operation in 1980. This unit was deferred when it was determined through economic studies that the Company could participate in a 650 megawatt western coal burning unit that was under construction by the Kansas City Power & Light Company. The Company owns a 12%

undivided interest in this plant (78 megawatts) which became commercial in May of this year. The second combustion turbine, having been committed for in 1976, is on site and will be installed in 1980 and made available for the 1981 summer peak load.

During the mid-year 1979 and 1980 the Company lost 61 megawatts of hydro plant capability which originated from hydro electric plants operated by the Southwestern Power Administration. This hydro peaking power was lost to preferential customers, and it was necessary for the Company to plan for the lowest cost replacement capacity which resulted in the installation of the combustion turbines. The Fuel Use Act of 1978 had a definite effect then on the Company's ability to burn oil on the existing 90 megawatt unit (commercial in February, 1978) and since the commitment had been made for the second unit, it was necessary to have both units classified as "existing" rather than "transitional" as they were originally classified by the Department of Energy. The Economic Regulatory Administration did effectively deal with the reclassification of the two combustion turbines from "transitional" to "existing." We have petitioned the Economic Regulatory Administration to substitute natural gas for the light oil requirements on the combustion turbines.

Due to the fact that new capacity is extremely costly the Company has re-evaluated present gas-oil burning capability. In addition to the combustion turbines, the Company has approximately 50 megawatts of gas-oil burning capability, and a determination has been made not to retire this capability. This determination was made because of the present cost per kilowatt of both new base load and new peaking capacity. Because of the adverse effect on the rate structure, it would be an injustice to our customers to retire gas and oil burning capacity in these times of economic distress.

During the years 1974 to 1976 inclusive the Company experienced its lowest consumption of natural gas, but the FUA bases the maximum amount of gas the utility can burn on the average amount burned during the years 1974 to 1976 inclusive. This was a time of relatively high oil burning for the Company because natural gas was not made available for the winter months, or for burner stability and start-up purposes. The demand on the gas-oil burning units during 1974 to 1976 was either purchased or generated by oil and small amounts of gas on a weekly allocation. An extremely rigid curtailment plan was instituted by the Company's gas supplier, Cities Service Gas Company,during this period. Still, the Company has to rely upon this number and our temporary public interest exemption (which may not be effective after 1985) for future gas burning capability and related emergency generation. The Department of Energy should realize that one broad basic law cannot be applied to all utilities without creating hardships and poor economic performance by the utility industry.

The Company believes strongly that we must reduce our oil consumption. We concur that this is in the national interest and can be in the interest of our consuming customers if the Fuel Use Act will first back the oil out of utility systems where possible, and let utilities such as the Company burn natural gas in order to maintain the use of the existing gas-oil burning capability. In other words, it is believed that the simultaneous backing-out of oil and natural gas is not in good judgement and is certainly not economically feasible for small companies such as ours.

Under the Natural Gas Policy Act, the deregulation of gas and the input of imported gas from Mexico and Canada will naturally have a depreciating effect on the burning of gas in power plant boilers. As the gas price increases, the Company will turn to more coal burning, if it is possible to obtain new capacity by participation with other electric utilities. Small companies, and a number of large companies alike, can no longer afford to build single coal burning electric generating facilities independently. Therefore, all future studies should be on a "joint use" basis, and again, timing is very important for these companies participating in a "joint use" plant. Premature removal of gas burning facilities will be a further stumbling block for injection of coal burning capacity into this Company's and other participating companies' systems. Proper timing of the additional capability will be essential to keep from extensive overbuilding with respect to the demand curve, which would impose a severe burden on the Company's customers with respect to rates they pay.

The Company has examined the Fuel Use Act closely and has studied the proposed amended "back-out" legislation. Under the State regulatory systems in which we operate it is necessary to have our plans for future power plants approved under a Certificate for Convenience and Necessity. To combine the back-out legislation and have all plans approved by both Federal and State agencies is a two-step process and felt to be unnecessary and unworkable. The Company believes that we must plan effectively, but planning twenty years in advance is unrealistic at this time. We must, however, establish new benchmarks on the demand curve so that over-build does not occur, which would greatly increase the cost to our customers.

The Company respectfully submits all of the foregoing comments for your study and consideration. Please advise this office of any questions you might have relative to this subject matter.

Very truly yours,

A. R. Puffinbarger

A. R. Puffinbarger:clh
cc: Mr. R. C. Allen
General Files

MINNESOTA POWER & LIGHT COMPANY
30 WEST SUPERIOR STREET DULUTH, MINNESOTA 55802
PHONE (AREA 218) 722-2641

G. B. OSTROSKI
Director of Planning

June 6, 1980

Mr. Alan W. Starr
Chief, Source Technology and Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

SUBJECT: Small Utilities Study
Powerplant and Industrial Fuel Use Act of 1978

Dear Mr. Starr:

Minnesota Power & Light Company (MP&L) and its wholly-owned subsidiary, Superior Water, Light and Power, with a 1655 MW electric generating capability, own two oil burning power plants. The M. L. Hibbard Plant is composed of four units with a total nameplate capacity of 124 MW. The two Winslow units total 25 MW. In addition, MP&L owns four units that require a coal/oil mix to achieve full nameplate capacity.

We are unsure as to whether the authority of the Secretary to prohibit excessive use of mixtures under the FUA would apply to our use of coal/oil mixes. The four units that presently use a coal/oil mix were originally constructed to burn Illinois high-sulphur bituminous coal. To lower energy costs and decrease the impact on the environment, MP&L switched to Western low-sulphur sub-bituminous coal. It is not possible to achieve full nameplate rating with the Western coal because of a lower heating value, therefore, oil is mixed with the coal when it is necessary to go from about 85% of capacity to full load. MP&L requests that coal/oil mixtures used for "topping" such as has been described not be prohibited. Prohibition would force MP&L to construct new generating capacity or revert to burning high sulphur coal; both alternatives would be a tremendous financial burden for the Company and its customers; furthermore, reconversion may no longer be possible under present and proposed environmental restrictions.

The Hibbard and Winslow plants, both located in urban areas, were originally constructed as base-loaded coal-fired power plants. At government prodding the units were converted to cleaner burning oil; the costs of conversion were borne by our customers, the environmental benefits accrued to all. Now, hardly ten years later, the government, through the FUA, is threatening to require an expensive reconversion to coal. What guarantee is there that another conversion is not ten years into the future? It is extremely difficult for MP&L to continuously raise huge amounts of capital; it is also extremely difficult to justify and expect that the consumer should pay for the multiple conversion when, in essence, they have not received any additional product for their money. The

FUA states as its intended purpose the reduction of petroleum imports as a method of preserving the national security. MP&L humbly submits that if conversion of units is required for national security, then Congress should allocate full funding for each and every required reconversion including licensing costs. If a reconverted plant could not be licensed because of environmental constraints, Congress should allocate funds to replace the lost capacity. Neither the small utility, nor its handful of customers should have to bear the financial burden of an Act that will benefit the nation as a whole.

MP&L's two oil-fired plants are presently used as peaking units. However, to declare the units as peaking units under the definitions of the FUA would severely restrict future operating flexibility. If capacity deficiencies occur in the future, peaking unit status would inhibit reliable service to our customers. MP&L requests that multiple exemptions be permitted so that the small utility has to prepare and argue one case only.

To obtain any exemption, the burden of proof resides with the utility. Analysis, documentation and preparation require the commitment of substantial manpower to an effort with no known level of success. Therefore, to minimize expenses, MP&L started investigating the potential for using both unusual fuels and unusual technologies at our oil burning plants. This is becoming a time-consuming and costly process. Only the largest utilities have the political clout and the sophisticated expertise that enables them to gain government grants, loans, etc. for such research. MP&L requests that Congress allocate funds for such research.

MP&L is strongly interconnected with other utilities (both larger and smaller). Planning and operating of the interconnected system is coordinated through the Mid-Continent Area Power Pool (MAPP) and the Mid-Continent Area Reliability Coordination Agreement (MARCA). In the interest of saving time and money, MP&L requests that the FUA make provision for the Power Pool to request public interest and reliability of service exemptions for any or all oil and gas burning power plants within the Pooling area. Giving recognition to strong interconnections, pool diversity, etc., MP&L could probably not say that an individual plant was needed for reliability of service. However, if capacity is lost on a piecemeal basis and not replaced because small utilities cannot raise the capital to build or join in the building of today's very expensive capacity, the Pool and all its member utilities could quickly discover that the electric system as a whole had become unreliable.

Our final comment has to do with the conflicting requirements of state and federal agencies. Unless MP&L can, in some way, secure an exemption, the FUA mandates the M. L. Hibbard plant be reconverted to coal or an alternate fuel. Currently, the Minnesota Pollution Control Agency (MPCA) is citing the plant for violating opacity standards by burning #6 fuel oil and urging MP&L to burn the cleaner neutral gas or #2 fuel oil. Obviously, MP&L cannot satisfy both the DOE and the MPCA. MP&L requests that DOE and Congress spell out a clear national policy as to what issue takes precedence and which agency has final authority in resolving the conflict over whether a given unit should burn coal to preserve our limited petroleum resource or burn oil to limit further environmental degradation when a plant is located in a sensitive area. Obviously, a small utility cannot settle the dispute between national security advocates and environmentalists. Yet, by abdicating their responsibility, Congress has placed an impossible burden on the small utility. To try and seek a compromise between the two agencies in the above example, MP&L is viewed on the one hand as un-American for not switching to coal and as anti-environment for not switching to #2 fuel oil or natural gas. Neither MP&L, nor any other utility, can successfully resolve this issue.

Very truly yours,

GBOstroski

G. B. Ostroski
Director Planning

GBO:am
COPY: J. F. Rowe

MISSOURI UTILITIES COMPANY
400 BROADWAY
P.O. BOX 40
CAPE GIRARDEAU, MISSOURI 63701
AREA CODE 314/335-9461

FRANCIS R. LENGEFELD,
PRESIDENT
J. R. LANSMON,
VICE PRESIDENT & TREASURER
VIRGIL CHIRNSIDE,
VICE PRESIDENT & SECRETARY

CURTIS LEVAN,
CONTROLLER & ASS'T. TREASURER
WELDON D. HILPERT,
ASS'T. SECRETARY

June 9, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
U. S. Department of Energy
Washington, D. C. 20461

RE Small Utilities Problems in Complying with the Powerplant and Industrial Fuel Use Act of 1978 (FUA)

Dear Mr. Starr:

Missouri Utilities Company offers the following comments concerning the referenced subject.

Missouri Utilities Company is a small investor owned utility engaged in the generation, purchase and sale of electric energy and the purchase and sale of natural gas within the State of Missouri. The company also provides water service in the City of Cape Girardeau, Missouri. As of December 31, 1979, the company rendered electric service to 58,527 retail customers and sold electric energy at wholesale to four cities.

The Missouri Utilities Company purchases in excess of ninety-nine percent (99%) of the electric energy it sells. The company only has remaining two power plants which are normally utilized about 100 hours per year. The one plant consists of two 1 megawatt diesel generators which are seldon utilized and the other plant consists of 33 megawatt natural gas fired turbine generator.

The company normally only uses the gas turbine generator for summer peaking; and then usually less than 100 hours per year. Fuel for the turbine generator is natural gas the company has normally purchased on a "take or pay basis" from our wholesale pipeline supplier and is left over after the winter heating season. There is presently no known supply of alternate fuel or equipment or combination of fuel and equipment which would enable the gas turbine generator to permanently comply with the Fuel Use Act (FUA).

Aside from the very fact of the existence of the prohibitions, our main problem with the FUA is that it seems to block entirely any use of the gas turbine on or after January 1, 1990. The rules list several possible reasons for which exemptions from the prohibitions may be granted. At first glance, it might appear that at least three of these might be promising for us. These are:

1. Lack of an alternate fuel
2. For emergency purposes
3. For peaking purposes.

However, various conditions attached to these provisions seem to rule out their availability to us.

At present there is no known alternate combustion fuel available for use in the turbine, except that it is possible to convert it to oil. At the present time this is not a viable alternative, since there is an even greater urgency to restrict the use of oil in power generation. In addition, electric power is included in the definition of "alternate fuel" as used in the Act. This would seem to eliminate exemption on the grounds of no alternate fuel supply, as long as replacement power can be purchased. During the summer peak, replacement purchased power may very well be from exempted oil or natural gas generation and the company's own less expensive "take or pay" natural gas could go unused.

Exemption for the reason of emergency use or for peaking purposes requires certification that the plant is used only for that one purpose. Our present situation does not permit such a certification. Even though normally we could comply, we are obliged to use the turbine for either, or both, purposes as conditions require.

The restriction on the amount of gas which can be burned between now and January 1, 1990 could be a serious problem to us under certain circumstances. The terms of the Act, coupled with our pattern of use of the turbine in recent years limit us to about 100 hours use per year. Under conditions which we consider normal for this time, that seems to be adequate. However, it might not be sufficient for our needs in some emergency where we might very well have to run the turbine in event of some apparatus failure. In such a case, the increased use of gas would be negligible as concerns the national supply, but we are still denied its use under the Act.

These sorts of situations may not be common to the entire industry. They may not even be common to small utilities as defined in the letter from DOE. However, they do exist for us, and they do have the potential for causing us serious problems.

We appreciate this opportunity to comment on our real problems with the Fuel Use Act and hope these difficulties can be alleviated by changes either in the regulations or in the Act itself.

Very truly yours,

Virgil Chirnside

jbg

PNM PUBLIC SERVICE COMPANY OF NEW MEXICO
Post Office Box 2267 / Albuquerque, New Mexico 87103

June 11, 1980

Mr. Alan W. Starr
Chief, Source Technology and
Economics Branch
Division of Power Supply and
Reliability
Economic Regulatory Administration
2000 M. Street N. W., Room 4002
Washington, DC 20461

Dear Mr. Starr:

Subject: Small Utilities Study

I am pleased to have the opportunity to submit comments on compliance problems with the Powerplant and Industrial Fuel Use Act of 1978 as it affects Public Service Company of New Mexico (PNM). Overall PNM is anticipating little difficulty in meeting the act's requirements.

During the early 1960s, PNM recognized natural gas and oil were high quality resources whose demand and price would increase steadily, yet were resources whose domestic supply would be exhausted in future years. Because minimizing dependence on high cost fuel resources made good economic sense, PNM set a goal to reduce its utilization of oil and gas to a low level. To achieve this, a multi-billion dollar construction program was implemented to build units utilizing more abundant, less costly fuels. Working closely with the New Mexico Public Service Commission has helped assure that adequate rate relief was available to meet construction capital requirements without governmental subsidies.

In conclusion, by the time the ban on the use of natural gas takes effect in 1990, it is anticipated that only two to three percent of the electrical energy generated by PNM will utilize oil and gas as the fuel source. Therefore, we do not foresee a requirement that legislative or regulatory changes are warranted for PNM's compliance with the act. Thank you again for the opportunity to provide comments on this important subject.

Sincerely,

J. D. Geist
President

SFA:sks

Upper Peninsula Power Company
616 Shelden Avenue
Houghton, Michigan 49931

Clifton F. Rogers
*Chairman of the Board
and President*

June 25, 1980

Mr. Alan W. Starr, Chief
Source Technology and Economic Branch
Division of Power Supply and Reliability
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Sir:

Your letter requesting response from small electric utilities regarding the Power Plant and Industrial Fuel Use Act of 1978 (FUA) arrived at our offices on May 27. It was not possible to prepare our comments by the June 6, 1980 deadline. I am forwarding comments at this time to illustrate this Company's concern and also in the hope that they will be of some help to the study group, even though they are late.

It is our understanding that FUA allows the Secretary of Energy to prohibit, by order, the use of petroleum in certain existing power plants and restricts the increased use of petroleum by certain existing power plants, unless a permit is ordered by the Secretary authorizing such use.

Upper Peninsula Power Company operates in the Upper Peninsula of Michigan, offering electric service to about 42,000 customers at the retail and wholesale-for-resale level. The Company's long-range planning strategy includes providing electric energy to its customers from coal-fired generating facilities within the service area, from firm power and energy sources outside of the service area, and from oil-fired gas turbines strategically located in the service area.

Oil-fired gas turbines offer a low capital-cost means by which emergency and peaking energy can be maintained. We strongly believe in the reduction of the use of petroleum as a primary source of fuel for the production of electric energy; however, we also believe that extreme caution should be exercised in the prohibition of its application for production of peaking or emergency energy requirements.

As this Company takes steps to gain access to large power plants in an effort to minimize our fixed costs and fuel costs, we expect to purchase energy from sources well outside of our service area. This energy will be transmitted over substantial distances on our transmission facilities and the transmission lines of other utilities. We do business in a sparsely populated area considerably north of the business centers of Lower Michigan and Wisconsin. We do not enjoy the luxury of a major transmission network over which this energy may be purchased. The reliability of the available transmission lines, in some cases, is limited and construction of sufficient transmission facilities to insure reasonable reliability cannot be supported by the customers in the area.

Part of our long-range strategy for obtaining a reasonably reliable energy source for our customers must, therefore, include emergency- and peaking-generation sources. The Company's planned reliance on oil-fired gas turbines will be limited. Our reliance on oil may increase unexpectedly at any time, however, as our customers' energy habits change or as unplanned loads develop. We make every reasonable effort to forecast loads accurately and to make provisions for serving those loads. In spite of these efforts, inquiries regarding significant new industrial loads in our service area surface with alarming frequency. Service to industrial facilities is vital to the local economy, yet these inquiries are seldom made with sufficient advance notice to enable our Company to include them in our planning cycle. Oftentimes, the only realistic way in which energy can be provided on time is through the temporary use of oil-fired gas turbines.

I respectfully request that the study group consider carefully the extreme importance of limited short-term utilization of oil-fired generating equipment as an expedient to providing energy to new loads which cannot be incorporated in the long-range planning of any small utility. I feel this is particularly important in this Company's service area because it is sparsely populated and the transmission networks serving the area are not substantial.

The Upper Peninsula, bounded by Lake Superior on the north, is presently interconnected with limited 138-KV transmission lines south to the State of Wisconsin. There is clearly a need for additional facilities in the near future. The cost of the required facilities which must be supported by the Upper Peninsula residents is clearly an impediment to agressive development. We are working toward transmission development in an economically responsible manner and, when successful, we will be able to participate in large power plant projects with neighboring utilities. Any action by the Congress which appropriately encourages the construction of transmission facilities should be considered in the interest of the intent of the Industrial Fuel Use Act of 1978.

Respectfully,

C. F. Rogers

C. F. Rogers
Chairman of the Board
and President

SMITH AND GILLESPIE ENGINEERS, INC.
POST OFFICE BOX 53138
JACKSONVILLE, FLORIDA 32201
(904) 353-8657

March 9, 1979

JAMES J. BERRY, P. E.
EXECUTIVE VICE PRESIDENT

Public Hearing Management
Economic Regulatory Administration
Department of Energy
Room 2313
2000 M Street, N.W.
Washington, D.C. 20461

Subject: Powerplant and Industrial Fuel Use Act of 1978
Docket No. ERA-R-78-19

Gentlemen:

Smith and Gillespie Engineers, Inc., is a direct successor, without change in management, to the firm of Smith and Gillespie Engineers; Smith and Gillespie Engineers, Inc., and its predecessor have engaged in the general practice of engineering for more than 39 years. During this time, the firm has been especially active in providing services to municipal electric utilities, including a number of small generating utilities.

As used in this letter, the term "small" is much more restrictive than the term as used in the Powerplant and Industrial Fuel Use Act of 1978. All of the generating systems are less than 150 megawatts in capacity.

The comments in this letter are applicable not only to these utilities, but to other small utilities, regardless of ownership, which presently provide a healthy competition in the electric utility industry and which have proven to be a beneficial factor insofar as the interests of the consumer are concerned.

These comments are in response to the rules published in the FEDERAL REGISTER, Volume 43, No. 223, Friday, November 17, 1978. Unless otherwise identified, references, where cited, are to paragraphs or page numbers in the aforementioned FEDERAL REGISTER.

1. GENERAL:

1.1 In view of the fact that the Act defines a small electric utility system as a system which has a total system generating capacity of less than 2,000 megawatts, and these comments are based on systems of 150 megawatts or less, it is necessary to use and define a term specifically covering utilities of such smaller size. Therefore, for purposes of these comments, the term "very small system" is used to identify systems with a total system generating capacity of 150 megawatts or less.

1.2 Systems of 150 megawatts or less, very small systems as defined herein, have made, and should not be restricted from continuing to make, significant contributions to the nation's consumers of electric energy and to the nation's economy as a whole. Very small systems have introduced a significant competitive element in the utility industry which has been a benefit to all consumers of electric energy, not just to the customers of the very small systems. Because of their size, they are denied the "advantages of scale" and therefore must improve their operation in other ways in order to remain competitive. One of the ways very small systems have made such improvements is to generate with the best fuel economy possible and to improve their ability in this regard by operating interconnected wherever possible, and more recently, by entering into agreements for joint ownership of larger nuclear or coal-fueled generating units.

1.3 In recent years, well before the federal government acted to promulgate rules and regulations such as those now under consideration, small utilities, individually and in cooperation with each other and with larger utilities, have entered into agreements whereby such small utilities can avail themselves of the benefits of nuclear and coal-fueled steam generation. Nuclear and coal-fueled generation are not feasible alternatives in the size increments which are appropriate for such very small systems. Generating systems of this size are, in general, able to utilize increments of generation in sizes of 25 megawatts or less. The realities of present day cost, not only for sites and equipment, but for preliminary studies and regulatory filings which must be satisfactorily completed, eliminate generating increments of such size from consideration insofar as nuclear or coal-fueled units are oncerned.

1.4 It is only through cooperation of a number of very small systems or of such utilities with one or more larger utilities that such preferred alternative sources may be used to provide the energy necessary to generate the electricity needed by such very small systems.

1.5 Although the preliminary steps for such individual development may have been completed, and in a number of cases the development is well under way, the actual availability of such generating capacity may still be a number of years off, and in the interim, the very small systems must maintain their economic vitality if the contributions which they will make to the development of such alternative sources are to become a reality.

2. Beginning on Page 53975, "Division V, Specific Comments Requested," of the "APPENDIX: DRAFT REGULATORY ANALYSIS," solicits comments "on any issue before we reach a final decision on these regulations, not only on the specific issues and alternative proposals we enumerate below." References made in the paragraphs following refer to the lettered subdivisions in this part of the report unless otherwise specifically identified.

2.1 Reference Paragraph "A. Competition": The statement is made, "Regulatory schemes may tend to build in advantages for existing and large firms and to stifle competition for new entries and expanding firms. We solicit comments on whether these proposed regulations or sections thereof are likely to have adverse, beneficial, or neutral impacts on competition."

2.1.1 The proposed regulations, if applied in the form proposed, and based on the criteria indicated in the FEDERAL REGISTER, would have an extremely adverse impact on the existing viable competition provided by very small systems.

2.1.2 For the most part, in virtually all cases, such very small systems, because of the characteristics of their generating equipment, site limitations, or other equally compelling reasons, have few choices as to fuel and may well have no alternatives other than oil or natural gas as fuel.

2.1.3 Because of their size, very small systems are also limited as to types of prime movers and sizes of increments of generation which they may elect to use. The successful operation of a very small system demands the development of a well-designed master plan for incremental expansion matched to system growth. Because of their size, the margins within which such systems must operate are small and do not permit incurring even interim non-productive capital investment or administrative, operating or maintenance expense to the same degree that could be incurred by a larger system.

2.1.4 A successful master plan for a very small system must be tailored to the specific needs of the particular utility. It must recognize limitations on increments of capital investment and at the same time provide capacity adequate to meet the realities of load growth. For example, the construction of a large shopping center may well utilize a substantial portion of an increment of expansion of a very small system whereas it would be only a small part of the normal expansion of a larger system. In order to provide for optimum development, it may be necessary to provide capacity in the form of intermediate duty generation which would operate in base load duty for a limited time, accepting the resulting higher operating and maintenance costs as a trade-off for short term savings in fixed costs.

2.1.5 However, both economic and reliability considerations demand that the master plan for continued expansion be followed based on reasonable application of scheduled investments of capital for programmed units of expansion. If it is not, the adverse effect on the economic and reliability vitality of the system is magnified.

2.1.6 Under these circumstances, the only alternative such very small systems would have would be to purchase their power requirements. In many cases, under one possible application of the proposed rules, this could mean that the very small systems would be forced into purchasing from their competition without any alternative. The history of the development of the electric utility industry is replete with examples of buy-out attempts and other anti-competitive practices under which a number of very small systems have been forced out of business when they either did not have or were not able to maintain viable alternatives to the purchase of electric energy from their competition. While it is true that there has been improvement in the cooperation between large and small utilities, the existence of anti-competitive practices has not been totally eradicated, as evidenced by cases filed within the last ten years before the various regulatory commissions and in the federal courts. Further, the cooperation that does exist developed under circumstances substantially different from the circumstances that will exist when the proposed rules become effective. It remains to be seen whether or not such a cooperative spirit will continue under the substantial adverse pressures which the proposed rules will impose on all electric utilities.

2.1.7 The anti-competitive pressures on very small systems which would be created by the proposed rules in their present form are not limited to the restrictions proposed on the choice of fuels and/or sources of power supply. Because of their size, such very small systems will be overwhelmed by the cost and manpower requirements to meet the administrative demands outlined under the proposed rules. Many of these very small systems have only two, or at the most, three people, available to meet such administrative demands, and for the most part, they are already overburdened to meet the reporting requirements now in effect to satisfy local, state and federal agencies.

2.1.8 Much has been said and written recently concerning similar demands as imposed on small business. Little attention has been paid to the demands placed on very small systems which, in many cases, and especially with generating utilities, are more severe than those imposed on the average small business.

2.1.9 These comments have as their basis primarily municipal electric systems. Such systems, by their nature, are forced to maintain a competitive position with their larger neighbors. Unless such very small systems, by virtue of the tangible and intangible benefits to their customers, are able to maintain a competitive position, they are particularly subject to the economic reality that either they produce or be eliminated. For the most part, wherever possible, such very small systems operate interconnected, either with area or regional pools, and in this manner not only promote the conservation of energy, but maintain their competitive position.

2.1.10 The Department of Energy and the Congress of the United States have both made clear their concern that the implementation of the Fuel Use Act not reduce competition. It is therefore believed that the fact that such very small systems are so gravely impacted by the proposed rules is due to inadvertence rather than to intent. In a number of instances, it is either stated or may be clearly inferred that the proposed rules are based on criteria addressed to the large generating systems and that separate criteria may well be in order for the small generating systems. It is evident that in the case of very small systems, those systems of 150 megawatts or less, that the development of separate and specific criteria addressed to the requirements of such very small systems is mandatory if they are to continue as a competitive factor in the electric utility industry.

2.2 Reference Paragraph "B. Urban policy":

2.2.1 Where very small systems are municipally operated, they are generally a significant factor in the local economy, not only insofar as the municipality itself is concerned, but considering the total economy of the entire service area.

2.2.2 In many cases, such generating plants may well be a significant employer in the community, and the elimination of such generating plants would have an adverse effect on employment in the area, not only through the elimination of jobs in the generating plant itself, but the elimination of a market for local businessmen who provide goods and services to such plants.

2.2.3 Many of the plants are in areas where the economy is fragile and where disruption of such economy could have adverse effects on individuals who are already economically disadvantaged. The consequences of such elimination would represent a severe economic setback to the vitality of the towns and cities where such systems are located.

2.3 Reference Paragraph "C. Filing fees":

2.3.1 The purpose of the proposed fees, that is, to recover to the extent practicable the cost incurred by the government in implementing the analysis required, is reasonable. However, the proposed application represents a distortion of economic ealities. The magnitude of the fees is such that they represent a disportionate share of the cost of doing business insofar as a very small system is concerned. The filing fees alone (not counting the cost of preparing the filings themselves) could well represent 20 percent or more of the administrative budget of such very small systems. Data filed by the American Public Power Association provides, in readily identifiable form, a summary of such costs for a wide range of municipal systems.

2.3.2 The expense of filing, including the filing fees, could well represent a deterrent factor that could prevent such very small systems from exercising what would otherwise be their rights, and could therefore administratively eliminate such very small systems as a viable competitive factor.

2.3.3 As expressed previously, separate criteria specifically addressed to the requirements of such very small systems is urgently needed, and in the development of such criteria, simplified filing procedures with filing fees eliminated or scaled down to realistic levels must be considered.

2.4 Reference Paragraph "G. Definition of units within aggregations":

2.4.1 Realistically, and based on precedent both in Congressional action and in Regulation, very small systems, 150 megawatts or smaller, should, as previously stated, be subject to separate criteria. In preparation of such criteria, consideration should be given to such utilities for which the proposed rules would be an unreasonable burden and where the establishment of separate criteria would have little, if any, impact on the national interest insofar as oil and gas savings are concerned.

2.4.2 Under such criteria, it is believed that the Act's power plant definition should be amended to provide that such criteria would apply to individual units of 25 megawatts rated net generating capacity or less, or to any unit which is a part of a system with a total net generating capacity of 150 megawatts or less.

2.5 Reference Paragraph "H. Reconstruction or refurbishment of power plants and installations":

2.5.1 In the development of separate criteria for very small systems, careful consideration should be given to the fact that some areas of the country, such as Florida, have statewide generating capability that is, for the most part, dependent upon natural gas or oil for fuel. It is in the national interest that where small plants can be modified (including such modifications as would require the addition of more efficient generating units utilizing oil or natural gas as fuel), such modification be considered on the basis of a criteria that would recognize that when alternate sources of replacement energy would, of necessity, require the use of oil and natural gas as fuel, and where such modification would result in an overall saving in the fuel required to produce the needed electricity, that such modifications be facilitated rather than handicapped.

2.6 Reference Paragraph "I. Fuels decision report":

2.6.1 In the case of generating units where existing technology, site restrictions or other readily identifiable factors preclude consideration of alternate fuels such as those cited in this paragraph, consideration should be given to development of a simplified fuels decision report.

2.7 Reference Paragraph "J. Cost calculations":

2.7.1 When one of the alternatives to be considered is purchased power, the true cost of providing purchased power should be the basis for consideration. This means that the purchase alternative should be evaluated on the basis of the incremental cost of production of such power by the supplying utility.

2.7.2 As cited in Paragraph 2.5.1, the comparison of purchased power alternatives must be realistically weighted to give consideration to the impact on the use of natural gas or petroleum products if the purchase alternative is followed.

2.7.3 In addition, where the systems which would supply such purchased power are faced with significant impact under application of the proposed rules discussed herein, the comparison of the purchased power alternative must be required to recognize the impact of such cost, not historical or current cost.

2.7.3.1 This is a further reason why separate criteria must be established for the very small systems. In a state such as Florida where the predominant existing generation is fueled by natural gas or petroleum, the effect on very small systems which must rely for all or part of their supplies on larger systems whose generation is predominantly fueled by natural gas or petroleum cannot be fully determined until the problems facing the larger utilities are solved.

2.7.3.2 Again using Florida as an example, full consideration must be given to the cost and problems of realistically providing adequate supplies of alternate fuel to the area.

2.7.4 Paragraph "J.2. Substantially exceeds index" invites comments on the magnitude of the index and whether the same index should be used for power plants, installations, purchased electric power, and for the general and special cost test.

2.7.4.1 The paragraph states the if "we (ERA) choose to use the method, the specific ratio selected as the index will probably be between 1.3 and 1.8, but a higher ratio may finally be selected." The statement that "a higher ratio may finally be selected" negates the effect of the statement that "a ratio of 1.6 is used in these proposed regulations for illustrative purposes."

2.7.4.2 This is overshadowed, however, by the fact that the minimum level cited, 1.3, it outside of any reasonable limit. In view of the widespread dependence on electric energy by all parts of the nation's economy, it is difficult to imagine ny more disruptive influence than to apply such levels of cost comparison to the decision-making process that would determine how the cost of electric energy will be impacted.

2.7.4.3 As detrimental as the effect would be on the electric utility industry and on the nation's economy as a whole, the application of such criteria to the very small systems of 150 megawatts or less would have a particularly devastating impact, since the decision could well be affecting increments of 30 to 40 percent or more of the system's total annual energy requirement. This further underscores the need for a separate criteria applicable to such very small systems.

2.7.4.4 In no case should any index approaching 1.3 or higher be applied to the alternative for purchased power cost. The criteria stated in the Act for the purchased power alternative is "reasonable." Forcing a utility to purchase power at levels which would insure the destruction of such a utility is completely beyond the bounds of reasonableness. The introduction of such a standard in the decision-making process would be distruptive in any business and devastating in the electric utility industry which has a demonstrable direct effect on the individual consumer and on the overall economy as well as on the viability of the utility itself.

2.7.5 The application of discount rates as proposed in Paragraph J.3. will adversely affect all municipal systems, and especially those very small systems of 150 megawatts or less. The rule should provide for the use of a discount rate based on the interest rate available to this class of utility, and the period of time used should be that for which financing is available. In addition, if calculations are o be based on fuel costs that do not include inflation, the comparable cost of money should be established by deleting from the rate applied in calculation the inflation factor on a current basis.

2.8 Reference Paragraph "L. Alternative power plant site - general requirement for permanent exemption":

2.8.1 This also provides an example why a separate criteria must be developed for very small systems. The size limitations applicable to such small systems preclude consideration of any significant separation of generating plants, and economic and operating considerations both would dictate that the limited increases in capacity appropriate to such systems should be located on existing sites wherever possible.

2.9 Reference Paragraph "M. Terms and conditions":

2.9.1 Special emphasis should be given to "requiring the use of effective fuel conservation measures which are practicable and consistent with the purposes of the Act." In applying this rule, full consideration should be given to proposed development plans which will have a beneficial rather than a detrimental effect on the overall consumption of natural gas or petroleum products.

2.10 Reference Paragraph "T. Intermediate load exemption":

2.10.1 The separate criteria which should be developed for very small systems of 150 megawatts or less should give consideration to the fact that such systems, of necessity, can participate in nuclear or coal-fueled generating units only through cooperative ventures with other systems and that their ability to diversify sources is limited. The need for such systems to maintain interim viability by use of the most efficient base load generation possible must be recognized, as must be the fact that such units, when phased out of base load service by the development of joint venture nuclear or coal-fueled plants, will be needed to provide the intermediate and/or peaking power requirements under normal operating conditions and to provide area protection when the remote plants are out of service for maintenance or other reasons.

3. There is no argument at all with the basic premise that conservation of petroleum products and natural gas is essential to the interests of all and that emphasis must be placed on those developments which will optimize the use of alternative fuels. In striving to meet this goal, however, full consideration must be given to the fact that the application of both manpower and capital, as well as the expenditure of funds for the administrative procedures, are all critical considerations if reasonable development is to be insured. The imposition of rules which require the expenditure of disportionate amounts of capital investment, manpower, or operating and administrative funds will be counterproductive and result in damage to the nation's economy.

4. Certain regions such as Florida where the nature of existing

generation, the lack of a local fuel source, problems with supplying coal as fuel, and other considerations result in conditions which are not duplicated elsewhere, require special attention in the case of all electric utilities, and because of the potential impact of the rules proposed on the larger systems, will have an accentuated effect insofar as the very small systems are concerned.

5. There are ambiguities as to the status of certain types of prime movers used by a number of very small systems, such as internal combustion engines. Comments on such installations are handicapped by these ambiguities and by the fact that the criteria on which the proposed rules are based fail, in so many respects, to recognize the realities of operation and development of very small systems of 150 megawatts or less. It is essential that separate criteria be developed for such very small systems.

Respectfully submitted,

SMITH AND GILLESPIE ENGINEERS, INC.

James J Berry

James J. Berry, P.E.
Executive Vice President

JJB:js

STONE & WEBSTER MANAGEMENT CONSULTANTS, INC.
GREENWOOD PLAZA, DENVER, COLORADO
ADDRESS ALL CORRESPONDENCE TO P.O. BOX 5406, DENVER, COLORADO 80217
303-770-7700

May 22, 1980

Mr. Alan W. Starr
Division of Power Supply and Reliability
U.S. Department of Energy
2000 M Street, N.W.
Washington, D. C. 20461

Dear Sir:

The following remarks are in response to the April 17, 1980 Federal Register notice regarding comments relative to Section 744 of the Powerplant and Industrial Fuel Use Act of 1978 (FUA). Section 744 requires the Department of Energy (DOE) to conduct a study of FUA compliance problems experienced by electric utilities with a total system generating capacity of less than 2,000 MW. Our review of FUA as it impacts small utilities concludes the following points.

- The regulatory burden of FUA is considerable and could pose significant difficulties in the development of compliance strategies for small utilities.

- The FUA regulations restrict the concept and promotion of power pooling.

- FUA discretionary fuel prohibitions impose an additional uncertainty on small utility decision makers and may negate their long-term planning effort.

- Successful FUA unit exemptions seem so unlikely that small utility decision makers may conclude they cannot afford the risk associated with this compliance option.

- The system compliance option exemption may not serve as a viable compliance option to small utilities because of the unreasonable time constraint imposed by FUA.

- FUA will encourage the displacement of natural gas with oil in powerplants where gas/oil dual firing ability exists.

Based on these observations, we respectfully submit the following recommendations.

- ERA should consider sponsoring FUA seminars explaining all the regulatory requirements of the Fuel Use Act.

- ERA should consider a "decision tree" format as a means of simplifying its regulations.

- If FUA seminars and simplified regulations are not possible, ERA should consider providing small utilities with other means of assistance to achieve an understanding of ERA programs.
- ERA should consider the possible advantages of allowing power pool participants the ability to exchange or transfer their individual gas volume allowances, under an SCO exemption, to other participants of the same power pool.
- Investigate a power pooling compliance concept as a means of reducing the regulatory burden of individual pool participants.
- ERA should consider ways to reduce or eliminate the additional uncertainty associated with the discretionary fuel prohibitions.
- ERA should consider reopening the SCO exemption option for small utilities.
- ERA should consider reducing exemption petition filing requirements for small utilities.

FUA Regulatory Burden

The FUA represents a substantial body of new information regarding powerplant boiler fuel constraints. FUA compliance requires powerplant owner/operators to collect, structure, study and understand these requirements. The initial effort would have to be increased to reflect the continuing effort to follow interpretations and changes to the original FUA information. Should the regulations require five years to mature, the monitoring effort in each utility is necessary for the same time span.

Only after powerplant owner/operators have achieved full understanding can they properly identify the complete impacts of FUA regulation. Impacts are defined in relation to specific conditions and individual powerplant units. The collection or development of historical powerplant unit fuel data represents considerable time and effort. The fuel data must be converted into standard units compatible with calculating the proportions required by the regulations. Only after this effort can owner/operators quantify specific fuel prohibition impacts.

The effort indicated above only provides a basis for compliance, but not a strategy for compliance. Developing a strategy would require additional study.

Stone & Webster Management Consultants, Inc. feels it is unreasonable to place such a burden on small electric utilities. Even if publication of the current regulations was simplified, small utilities would still face major problems in assessing impacts because they may not be able to afford the man power to study completely the law and implementing regulations.

We respectfully suggest this burden be removed or at least reduced by ERA sponsored seminars on FUA compliance that would be open to the public.

In addition the regulations could be reduced to a universal format such as "decision trees." The "decision tree" format is an accepted management tool and in many cases can greatly simplify complex and confusing issues. We urge ERA to undertake a campaign to provide owner/operators with a complete and clear understanding of these regulations.

Compliance Problems

Power pooling represents a proven concept in the promotion of efficient and reliable electric generation. ERA is committed to encouraging coordination among the nation's utilities under Section 202(a) of the Federal Power Act. ERA's position is clearly defined in the following paragraph taken from *Power Pooling: Issues and Approaches*, U.S. Dept. of Energy, Economic Regulatory Administration, Office of Utility Systems, January 1980.

> "The U.S. Department of Energy's Economic Regulatory Administration (ERA) has begun a comprehensive program to encourage increased coordination among electric utility systems. The primary objectives of this program are to stabilize or possibly lower utility operating and capital costs and lessen national dependence on imported oil. ERA's Office of Utility Systems have been delegated the responsibility of developing and implementing the initiatives necessary to accomplish these objectives."

At the present time the FUA does not seem to promote power pools or other joint action agencies because the current regulations do not encourage increased coordination among electric utility systems. The particular area of concern is in the system compliance option (SCO) exemption available to all owner/operators of existing electric powerplants. SCO regulations provide for the gradual phaseout of natural gas as a boiler fuel. Under an SCO, the gradual phaseout program allows certain natural gas volumes to be burned after 1990 . In our interpretation the current regulations prohibit the transfer of these natural gas volume allowances between petitioners. If a petitioner is a member of an operating power pool, this restriction could limit or prohibit the petitioner's participation in economic dispatching operations and increase oil consumption.

Power pooling arrangements not only provide for dispatch economies but also allow for savings in administration and fuel related contracted services. Economies through joint action agencies might reduce costs and the regulatory burden for small utilities.

Compliance uncertainty appears to be encouraged by the current FUA regulations. This uncertainty comes from regulatory requirements to meet discretionary fuel prohibitions and the structure of unit and system exemption options.

The FUA discretionary fuel prohibition regulations state that ERA may prohibit the use of petroleum or natural gas in existing electric powerplants if ERA finds that such powerplants have or had the technical capability to use coal or an alternate fuel and it is financially feasible to do so. This type of regulation requires the utility owner/operator to convert to alternate fuels when they become feasible. We submit it may not be in the public interest to promote certain alternative fuels because of environmental side effects. As currently written the discretionary regulations increase uncertainty in utility fuel problems if conversion is required. This type of constraint hinders long-term planning efforts and the stability such planning can bring.

The structure of the FUA exemption process is complex, and the utility owner/operator must make a business decision under uncertainty imposed under the FUA regulations. Uncertainty stems from the requirements of the individual FUA petitions and the inconsistent deadlines for system and powerplant unit exemption petitions.

Our analysis of exemption petition requirements indicates petitioners must spend considerable effort examining alternative fuels and then proving certain fuels are not feasible. This seems to be the intent of the information required in the Fuels Decision Report (FDR). The difficulty of producing FDR evidence such as regional loss-of-load probability (LOLP) or a complete environmental impact analysis is sufficient to cause utility decision makers to ponder the chances of a successful petition. Our analysis of all available powerplant unit exemptions indicates that at this time only four (4) unit exemptions can be rated as having a better than 60 percent chance of succeeding. None of these four exemptions are of the permanent type. The uncertainty associated with a successful powerplant unit exemption petition therefore seems substantial. Should a utility decision maker have the time and resources and agree with our analysis of unit exemptions probabilities, he could very likely conclude unit exemptions in general do not provide a reasonable compliance strategy. The utility decision maker might therefore eliminate from his options the unit exemption route, based on the conclusion that this compliance strategy presents too great a risk to his particular utility and its customers.

The only apparent alternative to the unit exemption strategy is the system compliance option exemption. This compliance strategy was offered as an interim rule in the June 20, 1979 Federal Register. While a small utility may have learned of this exemption option shortly after June 1979, it seems unreasonable to expect a small utility to have the resources to properly analyze this exemption option prior to its first deadline of January 1, 1980. Although the requirements of this deadline were minimal, the deadline date may have forced utility decision makers to make a critical decision with very little time for complete analysis. To consider properly the SCO exemption, a utility decision maker would have to study the unit exemption option and all other compliance strategies at the same time. In our opinion this specific deadline imposed an unreasonable burden on small utilities which has probably eliminated a viable compliance strategy for many of them.

Our analysis of the SCO exemption indicates the loss of the SCO exemption for utilities with gas/oil fired existing powerplants will likely increase oil consumption. Without the SCO exemption utilities can only try for unit exemptions which may involve unacceptable levels of risk. Assuming utilities are unsuccessful in their unit exemption petitions and have not met the January 1980, SCO filing deadline, these utilities will logically switch from natural gas to oil as a burner fuel. This switch is likely because of its existing dual firing capability and reluctance to invest in the facilities to burn alternative fuels. Such a scenario would not be in public interest as it would displace natural gas with oil and further the nation's problems with imported oil.

We believe ERA should consider reopening the SCO exemption option for small utilities in a manner that preserves this compliance strategy, affords an eligibility period equal to unit exemptions, reduces filing requirements, and achieves FUA goals.

We hope our thoughts and comments are helpful to ERA and the utility industry. Stone & Webster Management Consultants is ready to provide guidance and assistance as requested in relation to FUA.

Respectfully,

Peter J. Hamill
Senior Vice President

A. C. KIRKWOOD
& ASSOCIATES

ENGINEERS —•— CONSULTANTS

SUITE 200, PARKWAY 80 BUILDING
8080 WARD PARKWAY
KANSAS CITY, MISSOURI 64114
TEL.(816) 333-4477

May 22, 1980

Small Utilities Study
Office of Utility Systems
Department of Energy
Room 4002
2000 M Street N.W.
Washington, D. C. 20461

Re: PIFUA/1978 Section 744
Small Utilities Impact

We are consulting engineers to a number of truly small utility systems. We are responding in general to the request for comments under Section 744, not as utility operators but as consultants often dealing with such systems and their problems in attempting to coordinate their operations and planning with the present and future requirements of the FUA. I will limit our response to certain key, broad-scope areas and leave to the operating systems appropriate system-specific comments.

1. Definition of "Small Utilities". A 2000 MW demarcation is a non-sequiter that should never have been in the Act. A system approaching that size has few problems differing greatly from those much larger - of which there are relatively few. Conversely, the problems are significantly different for systems of substantially lower sizes. Probably three, maybe more categories should be considered. Breakpoints should have been closer to: 1000 MW and above; 200 to 1000 MW; 50-200 MW; and under 50 MW. These relate largely to the types of generating equipment most appropriate to and commonly used by systems of such sizes, and the fuels essential thereto. These divisions also correlate generally with the potential to impact the national energy scene - ie, the smallest systems, though fairly numerous, consume miniscule amounts of energy vis a vis the larger systems. At the least, your study of "small utilities" should so subdivide the analyses and results.

2. Fuel Guidelines. My comments hereinafter reference mostly the smallest category; these are the systems most likely to be interested in internal combustion engines (presently exempt under the FUA) and small combustion turbines, principally gas and oil

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fired. If they generated all-out (which they wouldn't), all such systems together are likely to consume less than 0.2% of the either oil and gas utilization in this nation (as substantiated in our response to the preliminary and interim FUA regs); a more realistic and open-handed approach to their fuel needs would seem eminently rational. This would enable them to maintain a more cost effective plan of operation, often utilizing off-peak energy from remote coal-fired and nuclear sources but generating on-peak and intermediate needs, and even baseloads when economically justified. This will relieve burdens on the larger systems, will disperse emissions, will improve local reliability for more remote systems, will help maintain local employment in small communities, and provide other benefits.

3. *Alternative Generation for Smallest Systems*. There are no extant cost-effective ways to use coal (or nuclear) in small generating units (viz, under 50 MW). And none appear to be approaching on the technological horizon; we are making studies for the Electric Power Research Institute in regards to small advanced-cycle systems and are fairly aware of the technological and economic barriers. Thus, greater flexibility in regards to coal/gas/oil are a must if small systems are to contribute beneficially to the generating mix of the nation.

4. *Fuel Costs*. For years U.S. regulatory patterns kept natural gas costs artificially low - leading to overuse and an unbalanced dependence thereon. Now, the NGPA and other regulatory policies are artificially raising prices to utilities and industries beyond actual cost-justification (all in an effort to induce resource development while artificially depressing residential-use prices). These 'man-made' manipulations are bound to further distort cost-effective and societally-beneficial free-market allocation of energy resources and rational development of alternatives.

5. *Force-Fed "Cooperatives"*. Power planners and operators need to have flexibility in meeting extant and growing loads. Being strait-jacketed into participation in remote plants, governed by others, often outlandishly expensive, is a potential death-knell to small systems. Participation should be encouraged and enabled, but the decision should be free. It isn't always the most beneficial, either economically nor operationally.

6. *Regulatory Procedures*. Large systems, having large impacts, are probably deserving of close regulatory scrutiny - such as in applications for exemptions. But smaller systems can ill-afford the expense, the lost time, or the legal and technical input to pursue exemption applications for co-generation concepts, hardship cases, etc. The thresholds should be revised higher, and be more flexible.

7. *Siting*. What is considered 'same-site' for a large utility or industry should not be so applicable to smaller systems. Nor should these regulations serve as a means to force 'cooperative' ventures (where the large members readily lord it over small members).

8. Alternative Technologies. It is unreal to expect substantial contribution from 'frontier' technologies (solar, wind, urban waste, etc.) to substitute substantively, nor soon, on power generation. Their development and adaptation should be supported; but meanwhile more traditional approaches must remain available. Extreme limits on gas and oil use (by fiat or by NGPA-raised prices) should not force small utilities out of generation; they'll seldom come back to use these low-grade energy alternatives when they do become available some several years hence, if ever found to be viable.

Thank you for your consideration of our comments.

A C KIRKWOOD
& ASSOCIATES

By:
B J Kirkwood
B. J. Kirkwood, P.E.

BJK/jw

LAW OFFICES
SPIEGEL & McDIARMID
2600 VIRGINIA AVENUE, N.W.
WASHINGTON, D.C. 20037
TELEPHONE (202) 333-4500
TELECOPIER (202) 333-2974

GEORGE SPIEGEL, P.C.
ROBERT C. McDIARMID
SANDRA J. STREBEL
ROBERT A. JABLON
JAMES N. HORWOOD
ALAN J. ROTH
FRANCES E. FRANCIS
DANIEL I. DAVIDSON
THOMAS N. McHUGH, JR.
DANIEL J. GUTTMAN
PETER K. MATT
DAVID R. STRAUS

OF COUNSEL
LLOYD E. DIETRICH

BONNIE S. BLAIR
ROBERT HARLEY BEAR
THOMAS C. TRAUGER
JOHN MICHAEL ADRAGNA
CYNTHIA S. BOGORAD
GARY J. NEWELL
MARC R. POIRIER
MARTA A. MANILDI
JOSEPH L. VAN EATON
STEPHEN C. NICHOLS

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Alan W. Starr
Small Utilities Study
Office of Utility Systems
Economic Regulatory
  Administration
Department of Energy
Room 4103
2000 M Street N.W.
Washington, D.C. 20461

Re: Compliance problems of small systems

Dear Mr. Starr:

This is in response to the Department of Energy's request for information and comments concerning the problems of compliance with the Fuel Use Act of 1978 experienced by electric utilities with a total system generating capacity of less than 2,000 Mw. The following comments are submitted on behalf of eight municipally-owned and operated electric systems in Florida, each of which has a total generating capacity of less than 2,000 Mw: the Cities of Gainesville, Lakeland, Tallahassee, and Vero Beach and the Ft. Pierce Utilities Authority, the Lake Worth Utilities Authority, the New Smyrna Beach Utilities Commission, and the Sebring Utilities Commission.

Summary. The Fuel Use Act causes two major problems for small electric systems. First, with regard to existing units the Act curtails the use of gas in the 1980's, and the Act stops or sharply curtails the use of gas after 1989. Gas-capable units must use oil if gas is restricted. That will worsen our nation's dependence on imported oil. Or, if oil is uneconomic or unavailable, the units must shut down. The problem is exacerbated for small systems, because in Florida and other regions small generating systems are more dependent on oil-fired and gas-fired capacity than are larger systems. The Act thus restricts smaller systems disproportionately and puts them at a competitive disadvantage.

Many small systems in Florida and perhaps elsewhere are at a special disadvantage during the 1980's. Their gas was steeply curtailed during the base period, while the gas supply of the major electric utilities that compete with them was not curtailed. The problem has been alleviated during the early 1980's by ERA's granting temporary public interest exemptions, which free the electric systems from their base period gas constraints. However the problem will recur when those exemptions terminate.

The Act offers other exemptions and options that may alleviate the gas restrictions on existing powerplants of some small systems. However, the exemptions are forbiddingly complex and for the most part require rigorous proofs that are costly to prepare. The burden falls heavier on smaller systems, which are less able than larger systems to spread the cost of preparation and the consequences not getting an exemption.

Perhaps the best cure is to amend the Fuel Use Act to drop the restrictions and prohibitions against the use of gas in existing gas-capable powerplants. That will not jeopardize high priority gas customers such as homes or hospitals, which will be first to get gas when demand exceeds supply.

Second, with regard to new powerplants, the Act generally prohibits electric systems from constructing new gas-fired or oil-fired powerplants. Unfortunately, the Fuel Use Act and other laws do not assure that small electric systems will have ready or equitable access to participation in large, economical coal and nuclear powerplants or to necessary transmission services. Beginning in the 1990's the Act may accordingly disadvantage many small systems and may force some of them out of business. The cure here is to require that large systems allow small systems to participate in or purchase power from major powerplants and allow small systems access to transmission networks on equitable and competitive bases.

Gas and oil dependence. The Florida municipal electric systems are disproportionately dependent, for past economic reasons, on oil and gas-fired generating capacity. They are trying to break out of that dependence. Gainesville and Lakeland are constructing coal-fired units. Several of the systems own small shares in Florida Power Corporation's Crystal River 3 nuclear unit. Several of the Cities are seeking participation and/or power from other nuclear units under construction. All their existing generating capacity, however, is gas or oil-fired. If the Fuel Use Act succeeds in its objective of stopping or severely restricting gas firing in existing powerplants by the 1990's, the municipal systems must then switch to oil if it is economical or available. To the extent oil is not available, the capacity will literally become useless. By contrast, Florida Power Corporation's generation is approximately 50% coal and nuclear. See Florida Power Corporation, 1979 Annual Report, page 7. Florida Power & Light Company reports that in recent years nuclear power has accounted for one-fourth to one-third of its generation. See Prospectus dated May 8, 1980, page 15.

Gas base period. Section 301(a) of the Fuel Use Act restricts gas burning in existing powerplants during the 1980's in proportion to the gas burn during the base period 1974-1976. For utilities that use the system compliance option, Section 501 of the Act may lead to other restrictions during the 1980's, and Section 501 will restrict gas burning in the 1990's partly on the basis of the system's 1976 gas burn. Most of the municipal electric generating systems in Florida purchase gas directly from the major pipeline that supplies peninsular Florida, Florida Gas Transmission Company. Those municipal electric systems were steeply curtailed in 1974-1976, especially in 1976. Therefore, Sections 301(a) and 501 fall heavily on those municipal electric systems. By contrast, Florida Power & Light and Florida Power Corporation, which purchased gas directly from gas producers (with Florida Gas Transmission serving as a transporter for the electric companies' gas), were not curtailed in the base period. Thus, the Fuel Use Act imposes base period limitations unequally, to the competitive disadvantage of the smaller systems.

Furthermore, if Florida Gas Transmission has gas to sell the Cities but they are restricted by the Act from using it, the gas will not be saved for the future; it will simply be sold off to Florida Power & Light Company and Florida Power Corporation, pursuant to recently reactivated "primary interruptible gas contracts" with Florida Gas Transmission Company, at least during the 1980's.

The Federal Energy Regulatory Commission has questioned the propriety of Florida Gas Transmission's past curtailments and has initiated an investigation of the matter, FERC Docket No. IN78-2. Because of the contractual relationships involved, Florida Power & Light has been made subject to the investigation. However, whether or not the FERC determines that the curtailments were unjustified, the Fuel Use Act does not appear to allow any adjustment of the small systems' disproportionately low base period limitations.

ERA has issued temporary public interest exemptions to the municipal electric systems and others, authorizing the use of gas to displace oil in existing powerplants. Florida Gas Transmission now has an ample supply of gas, so the exemptions granted by ERA have temporarily afforded substantial practical relief to the small systems in Florida. The exemptions have saved the affected municipal electric systems and their ratepayers an enormous amount of money and, of course, have reduced oil imports at the same time. On average the affected systems are saved over $9.90 per 1,000 kilowatthours. (One-thousand KWh is a typical amount of residential electricity usage per month.) When the temporary exemptions end, however, the Fuel Use Act will impose severe restrictions on those smaller systems, unless they receive permanent exemptions for their existing facilities.

Onerous exemption proceses. Some of the smaller systems may be able to escape the restrictions on burning gas in existing units, by winning permanent exemptions for some or perhaps all of their existing facilities. However, on their face the Fuel Use Act's provisions for exemptions seem deliberately complex, and they are costly to pursue. Even if ERA ultimately waives various requirements for fees and evidence, the municipal electric systems need nevertheless to hire lawyers and consultants to advise them of their rights and obligations under the Act. That costs money. Furthermore, waivers of fees and evidence would not be granted except in obvious cases; and even in obvious cases, with waivers, the Act costs the small systems many thousands of dollars to study and pursue exemption possibilities.

Section 501 of the Fuel Use Act offers an alternative, the system compliance option, but it has a serious flaw. Once a system's proposed compliance plan is approved by ERA, the system may receive no further exemptions for existing facilities (except for an emergency exemption). Even if a system is entitled to and prefers a permanent exemption for one or more of its powerplants, the system must nevertheless pursue the compliance option and run the risk of cutting off its exemption rights -- unless it wants to place all its bets on winning the permanent exemption. The Fuel Use Act should be amended to leave both avenues open, exemptions where applicable and the compliance plan for other units, with ERA regulating the compliance plan to prevent any system from over-reaching.

New powerplants. The Fuel Use Act generally prohibits large systems as well as small systems from building new powerplants to use natural gas or petroleum. However, the Act does not put small systems on the same footing as large systems, because as a practical matter coal and nuclear powerplants must be large to be fully economical and most small systems cannot afford to undertake a large coal or nuclear power project, except by participating with others in a jointly-owned facility. Moreover, small systems need access to major transmission networks in order to reach the large plants and to engage in the various power sales and other transactions that help make such projects practical and economical. Otherwise, the small systems are at a competitive disadvantage with the larger systems.

As for participation in the transmission network, some power pools allow small systems to participate fully in the transmission network and enjoy all its advantages. For example, the New England Power Pool allows small as well as large systems to participate in the transmission network. There are pools such as the MAPP pool which allow small systems to participate in the transmission network if they construct or purchase sufficient transmission facilities, though the MAPP pool agreement is unclear on what is sufficient. In peninsular Florida, however, the major utilities have not acceeded to the requests of small systems for access to the transmission network. (Small systems proposed to construct transmission facilities in cost-proportion to their use of the transmission network for loads not satisfied by local generation.)

As for participation in powerplants, Section 105 of the Atomic Energy Act authorizes the Nuclear Regulatory Commission to open nuclear power projects to participation by smaller systems, generally after lengthy and controversial antitrust reviews. Access to nuclear projects should instead be opened to smaller systems without their having to prove, in effect, that the exclusion would violate the antitrust laws. So far as we know, no law entitles small systems to participate in major coal power plants. Disadvantaged municipal systems must fall back on their rights to enforce the antitrust laws, a difficult and costly road toward participation in coal-fired powerplants.

Conclusion. The Florida municipal systems are disadvantaged by the Fuel Use Act, more so than major electric utilities, because the small systems have a higher proportion of oil-fired and gas-fired generating capacity; they are more vulnerable to the Act's prohibitions and restrictions on gas-firing in existing powerplants. Exemptions may alleviate the problem in some instances, but exemptions are generally hard to get and costly to get. With regard to new power plants, the Fuel Use Act disadvantages small systems in a different way, by omission. The Act generally prohibits small and large systems from constructing new gas-fired and oil-fired powerplants; but the Fuel Use Act does not lower the hurdles that now impede Florida municipal electric systems from ready and equitable access to the transmission network and to large coal-fired and nuclear power plants, which are being and will be built by the larger utilities. Without that access many small systems will be left high and dry by the Fuel Use Act.

(1) The Florida municipal systems therefore recommend eliminating the Act's restrictions on gas in existing powerplants. Higher priority gas users will not thereby be deprived. When gas is short, the higher priority users will be first to get the gas, and powerplants will be among the first to be curtailed. (2) Also, the restrictions on construction of new gas-fired or oil-fired powerplants should be matched with new legislation that better enables small systems to gain access to transmission networks and to power from, or participation in, major coal-fired and nuclear powerplants.

Respectfully submitted,

Alan J. Roth

Alan J. Roth

Attorney for the Cities of
Gainesville, Lakeland, Tallahassee,
and Vero Beach and the Ft. Pierce
Utilities Authority, the Lake Worth
Utilities Authority, the New Smyrna
Beach Utilities Commission, and the
Sebring Utilities Commission

APPENDIX I

SECTION 744, POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

SECTION 744. STUDY OF COMPLIANCE PROBLEM OF SMALL ELECTRIC UTILITY SYSTEMS

(a) STUDY.—The Secretary shall conduct a study of the problems of compliance with this Act experienced by those electric utility systems which have a total system generating capacity of less than 2,000 megawatts. The Secretary shall report his findings and his recommendations to the Congress not later than two years after the effective date of this Act.

(b) AUTHORIZATION OF APPROPRIATIONS.—There is authorized to be appropriated to the Secretary for the fiscal year 1979 not to exceed $500,000 to carry out the provisions of this section.

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